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Zhuo Zhou, China
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Alberta
OIL SANDS TECHNOLOGY
AND RESEARCH AUTHORITY

CHINA - CANADA HEAVY OIL TECHNOLOGY SYMPOSIUM

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RESEARCH AUTHORITY

RESEARCH INSTITUTE OF PETROLEUM
EXPLORATION AND DEVELOPMENT

CO-SPONSORED BY

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LIAOHE PETROLEUM EXPLORATION BUREAU

XINJIANG PETROLEUM ADMINISTRATIVE BUREAU

October 1987

Zhuo Zhou, China

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CHINA-CANADA HEAVY OIL TECHNOLOGY SYMPOSIUM

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PREFACE

AOSTRA

Alberta has one of the world's largest accumulations of bitumen and heavy oil not recoverable by conventional petroleum production methods. The Alberta Oil Sands Technology and Research Authority (AOSTRA) was established by the Government of Alberta in 1974, with a mandate to develop technology to realize the potential of our province's vast heavy oil and oil sands deposits. Although AOSTRA has been in existence for only 13 years, it has made a significant contribution, in concert with private sector companies, in the establishment of a highly technical and versatile oil sands and heavy oil industry in Canada.

On the other side of the Pacific, the People's Republic of China (PRC) has found oil and natural gas in two-thirds of its provinces. In recent years China has devoted much effort to developing its heavy oil resources and has identified the development of the heavy oil industry as one of 38 vital national projects under the sixth Five-Year Plan. In 1986, the total output of heavy oil in China reached three million tons. Importing advanced technology and equipment, and exchanging experience with other countries will help China to achieve its goals and meet its target in heavy oil exploration and production within this time frame.

AOSTRA recognizes that maintaining an international awareness and a knowledge of the nature of the petroleum resource industry throughout the world is a vital element in the development of viable technology. We have, therefore, endeavored to be aware of all the variations in the occurrence and nature of the resource and to assist others to understand and apply the technologies we have developed. To achieve this objective, technology exchange agreements have been signed with many foreign organizations. As these agreements are often the forerunners of trade with other countries in the petroleum equipment, engineering, and service industries, they are an important part of Alberta's technology transfer program.

Since 1982, AOSTRA has signed letters of cooperation with four organizations in PRC: the Daqing Petroleum Administrative Bureau, the Liaohe Petroleum Exploration Administrative Bureau, the Xinjiang Petroleum Administrative Bureau, and the Research Institute of Petroleum Exploration and Development (RIPED).

Subsequent to signing the letter of cooperation with RIPED, negotiations were carried out to develop a cooperative research program between AOSTRA and RIPED. On June 16, 1986, a cooperative research agreement was signed in which six projects were identified and are now underway. One of these projects addresses the need of holding technical heavy oil recovery meetings in China and Alberta. To meet this objective, AOSTRA set aside a special session during its 1986 conference on "Advances in Petroleum Recovery and Upgrading Technology", which was devoted to the Chinese heavy oil occurrences and technology. RIPED sent a three-man delegation and presented five papers in that session. In return, a heavy oil technology symposium is being held in China in October 1987. Since last fall, AOSTRA staff have been working closely with RIPED staff in organizing the technical program of the symposium. Under the arrangement between AOSTRA and RIPED, AOSTRA is responsible for translating 23

Chinese papers into English and for printing the English version of the proceedings, while RIPED is responsible for translating 27 Canadian papers into Chinese and for printing the Chinese version of the proceedings.

AOSTRA, with the cooperation of the Alberta Department of Economic Development and Trade, and the Canadian Departments of Regional Industrial Expansion and External Affairs, consider this heavy oil technology symposium a major event of international cooperation between Canada and China. It will be seen as an important milestone in technical cooperation between Alberta and China.

Many people have helped in many ways and it is a pleasure to thank them all. First, we express our gratitude to the Government of Alberta for its support and to the Government of Canada for providing assistance to industrial speakers, through the National Trade and Strategy Fund, to travel to China. We would like to thank the Sino-Canada Culture Association in Calgary for assisting AOSTRA in the translation of 23 technical papers into English within a very short time period. We also would like to thank all the authors from government institutions, universities, as well as the private sector of the petroleum industry, from both Canada and China, for their valuable contributions to the technical program of this symposium. Last but not least, all support and assistance provided by RIPED is gratefully acknowledged.

W.J. Yurko

Chairman and Chief Executive Officer

AOSTRA

RIPED

The Research Institute of Petroleum Exploration and Development (RIPED), established in 1956 in Beijing, is now a unique national composite research center for oil and gas exploration and development under the leadership of the Ministry of Petroleum Industry (MOPI) of China.

RIPED consists of the following departments: petroleum exploration; remote sensing; reservoir engineering; petroleum chemistry; enhanced oil recovery; drilling technology; world oil and gas fields; petroleum reserves; petroleum history of China; computer center; geological laboratory; machine shop; graduate school; and a branch institute located in Langfang. The technical staff of RIPED includes 1360 people working as geologists, geophysicists, other scientists, engineers, and technicians. Among these technical people are some 300 who can be classified as senior engineers, professors, or assistant professors, many of whom are national leaders in their fields. There are also about 500 active engineers working on various projects and about 170 graduate students studying in RIPED.

The gross annual oil production of China has exceeded 100 million tons since 1978, and in 1986 was 130 million. As a result of this present production, the oil and gas industry is already very important in China, and it is expected that this industry will become more important in the future. As part of its responsibilities for present production and for anticipated improvements, RIPED provides the Ministry of Petroleum Industry of China with up to date information about frontier exploration areas and about technical advances coming from recent research, along with appropriate research reports. In addition, RIPED is responsible for carrying out oil field development and design work, including development of new drilling and production technologies for most of the Chinese oil fields. As part of these responsibilities, RIPED is carrying out 40 research projects for the Ministry of Petroleum Industry and 17 projects for other Chinese government agencies. RIPED also has cooperative research arrangement with operators of all the Chinese oil fields and several other research institutes in China, and has signed 12 cooperation agreements with research organizations in other countries (Canada, USA, Great Britain, France, Germany, Japan, Venezuela, etc.).

We are pleased to report that useful results have been achieved as a result of the agreement of cooperation that was worked out and signed by RIPED in China and AOSTRA in Canada. The China-Canada Heavy Oil symposium, organized jointly by RIPED and AOSTRA, to be held in China in October 1987, is one of the six projects specified in the RIPED agreement with AOSTRA. I believe that this symposium will strengthen and broaden the China-Canada cooperation for heavy oil development.

I am pleased to have this opportunity to offer my thanks to the Ministry of Petroleum Industry of China, the Bureau of Foreign Affairs, Science and Technology, and Oil Field Development of MOPI for their support of this symposium. Thanks are also given to the Liaohe Petroleum Bureau and the Xinjiang Petroleum Bureau for organizing this meeting with us. We very much appreciate all the papers prepared for this symposium by the authors from government agencies, universities, research organizations, and industry of both countries. Finally, I offer my special thanks to AOSTRA for their effective efforts that have made possible this jointly sponsored symposium.

Zhai Guangming

President Research Institute of Petroleum Exploration and Development Beijing

PROGRAM

October 25, 1987

14:00--18:00	Registration
17:30	Reception dinner hosted by Mr. G.M. Zhai, President of RIPED

October 26, 1987

OPENING CEREMONY (Combined with Drilling Technology Seminar)

09:00--09:10	Welcome speech (G.M. Zhai, RIPED)
09:10--09:20	Welcome speech (W.J. Yurko, AOSTRA)
09:20--09:30	Welcome speech (Chinese Petroleum Society)
09:30--09:40	Welcome speech (CIM/CPI)
09:40--10:10	Opening remarks (Minister, MOPI)
10:10--10:40	Opening remarks (Ambassador of Canada)
10:40--11:00	Coffee
11:00--11:30	Opening remarks (Minister, Alberta Economic Development and Trade)
11:30--12:30	Cocktail reception hosted by His Excellency, the Ambassador of Canada
12:30--13:30	Lunch

GENERAL TECHNICAL SESSION

Presiding:
Mr. J.Y. Hu, RIPED
Dr. D.A. Redford, AOSTRA

13:30--14:30	1	Heavy Oils in China: their geochemical and geological aspects (J.Y. Hu)
14:30--15:30	2	AOSTRA heavy oil and bitumen in situ pilots (D.A. Redford)
15:30--16:00		Coffee
16:00--17:00	3	Standard for heavy oil classification, and thermal recovery sieving (W.Z. Liu)
17:00--18:00	4	Well completions for heavy oil production (M. E. McCormack)
18:00		Dinner

October 27, 1987

SESSION I-1 GEOLOGY AND FUNDAMENTAL RESEARCH

Presiding:
Professor L.G. Hepler, University of Alberta
Mr. L.C. Zhao, Xinjiang Oilfield
Room A

08:30--09:30	5	Geochemistry of continental heavy oils from China (Z.Q. Yang)
09:30--10:00		Coffee
10:00--11:00	6	Geology and the origins of heavy oil from the northwest Junggar Basin (R.Q. Yang)
11:00--12:00	7	The role for reservoir engineering research (D.A. Redford)
12:00--13:30		Lunch
13:30--14:30	8	Simulation of steam drive in a heterogeneous reservoir (J.H. Zhai)
14:30--15:30	9	Scaling laws for enhanced oil recovery experiments (S.M. Farouq Ali)
15:30--16:00		Coffee
16:00--17:00	10	Heats of combustion of light and heavy oils (H.K. Yan)
17:30		Dinner

SESSION II-1 DRILLING, WELL COMPLETION, AND PRODUCTION

Presiding:
Dr. C. Hsi, AOSTRA
Mr. W.Z. Liu, RIPED
Room B

08:30--09:30	11	Slant and directional drilling (R.D. Edwards)
09:30--10:00		Coffee
10:00--11:00	12	Slant wells in the Lindbergh heavy oil development (B.W. Stasiuk)
11:00--12:00	13	Technical study on the pumping techniques for Gaosheng heavy oilfield (Q.Z. Jia)
12:00--13:30		Lunch
13:30--14:30	14	The determination of polished-rod load in pumping of deep heavy oil well (H.X. Wang)
14:30--15:30	15	Sucker rod pumping system for cyclic steam stimulation projects (T.X. Qi)
15:30--16:00		Coffee
16:00--17:00	16	Specially designed pumps for heavy oil production (D.W. Gilby)
17:30--18:30		Dinner

October 28, 1987

SESSION I-2 GEOLOGY AND FUNDAMENTAL RESEARCH

Presiding:
Mr. L.C. Zhao, Xinjiang Oilfield
Professor L.G. Hepler, University of Alberta
Room A

08:30--09:30	17	Thermodynamics and colloid science applied to oil sands and heavy oils (L.G. Hepler)
09:30--10:00		Coffee
10:00--11:00	18	Measurement and correlation of equilibrium properties applied to bitumens and heavy oils (C. Hsi)
11:00--12:00	19	Use of foam forming surfactants to enhance the recovery of heavy oils (E.E. Isaacs, J. Li)
12:00--13:30		Lunch

SESSION III-1 RESERVOIR ENGINEERING AND PILOT TESTING

Presiding:
Professor S.M. Farouq Ali, University of Alberta
Mr. Q.H. Wang, Liaohe Oilfield
Room A

13:30--14:30	20	Effects of oil viscosity on the steam recovery efficiency (Y. Cheng)
14:30--15:30	21	Characteristics and recovery methods of heavy oil reservoir in Liaohe oilfield (Y.W. Xia)
15:30--16:00		Coffee
16:00--17:00	22	The feasibility study of steam injection recovery for thin sands (Q. Jiang)
17:30		Dinner

SESSION II-2 DRILLING WELL COMPLETION AND PRODUCTION

Presiding:
Mr. W.Z. Liu, RIPED
Dr. C. Hsi, AOSTRA
Room B

08:30--09:30	23	Primary sand control technology for Liaohe heavy oilfield (F. Zhou)
09:30--10:00		Coffee
10:00--11:00	24	Quartz sand as a gravel packing material in huff & puff wells (D.Z. Chen)
11:00--12:00	25	Sand control techniques for thermal recovery of heavy oil (T. R. Heidrick)
12:00--13:30		Lunch
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SESSION IV-1 SURFACE FACILITIES AND UPGRADING

Presiding:
Mr. C.W. Miao, PPEI
Dr. J.K. Liu, Syncrude
Room B

16:00--17:00	28	Heavy oil production systems (R.T. Clare)
17:30		Dinner

October 29, 1987

SESSION III-2 RESERVOIR ENGINEERING AND PILOT TESTING

Presiding:
Mr. Q.H. Wang, Liaohe Oilfield
Professor S.M. Farouq Ali, University of Alberta
Room A

08:30--09:30	29	Pilot experiments of steam injection at Shanjiasi heavy oil field (S. Huang)
09:30--b0:00		Coffee
10:00--11:00	30	Design and operation of a steam pilot (M.E. McCormack)
11:00--12:00	31	Production pattern of the cyclic steam pilot at Karamay No. 9 oilfield (R.S. Ni)
12:00--13:30		Lunch
13:30--14:30	32	The feasibility study of a heavy oil project (J.H. Nicholls)
14:30--15:30	33	Seismic monitoring techniques for remote sensing of heavy oil in situ heat movement (N. Pullin)
15:30--16:00		Coffee
16:00--17:00	34	Quantitative application of seismic data for heavy oil projects (R.C. Mummery)
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SESSION IV-2 SURFACE FACILITIES AND UPGRADING

Presiding:
Dr. J.K. Liu, Syncrude
Mr. C.W. Miao, PPEI
Room B

08:30--09:30	35	Surface facilities design - central plant (R.G. Holcek)
09:30--10:00		Coffee
10:00--11:00	36	Heavy oil gathering and transportation technology for Gaosheng Oilfield (Y.S. Chen)
11:00--12:00	37	Steam distribution, control, and metering systems (R.G. Holcek)
12:00--13:30		Lunch
13:30--14:30	38	Heavy oil gathering and pipelining technology (Z.F. Chen)
14:30--15:30	39	Rheology of Shanjiasi heavy crude/water emulsions (J.J. Zhang)
15:30--16:00		Coffee
16:00--17:00	40	Produced water treatment technologies for re-use or disposal (A.M. Somani)
17:30		Dinner

October 30, 1987

SESSION III-3 RESERVOIR ENGINEERING AND PILOT TESTING

Presiding:
Professor S.M. Farouq Ali, University of Alberta
Mr. Q.H. Wang, Liaohe
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09:30--10:00		Coffee
10:00--11:00	42	Economic evaluation of heavy oil projects (F.J. Werth)
11:00--12:00	43	Economical evaluation for steam injection recovery (R.C. Liang)
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13:30--14:30	44	Financing a heavy oil development project (P.A. Ross)
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SESSION IV-3 SURFACE FACILITIES AND UPGRADING

Presiding:
Dr. J.K. Liu, Syncrude
Mr. C.W. Miao, PPEI
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10:00--11:00	48	Analytical technology for heavy oil upgrading (J.K. Liu)
11:00--12:00	49	CANMET hydrocracking process demonstration plant operating experience (G. Muir)
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13:30--14:30	50	How to select an upgrading process to suit your needs (J.K. Liu)
14:30--15:00		Coffee
15:00--17:00		Panel Discussion "What does China need to upgrade her heavy oil?" Panel Member: Mr. C.W. Miao (Chairman), Dr. J.K. Liu Mr. G. Muir TBA (MOPI) TBA (PPRI)
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1

HEAVY OILS IN CHINA: THEIR GEOCHEMICAL AND GEOLOGICAL ASPECTS

Hu Jianyi
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ABSTRACT

The formation of heavy oils in China were controlled by biodegradation, secondary migration, reactions with aquifers, flushing by meteoric water, and oxidation by air. Oil normally varies from light oil at structurally low areas or in older formations to heavy oil at structurally high areas or in younger formations.

INTRODUCTION

Chinese petroleum basins were developed on pre-Sinian cratons and in folded belts of various geological ages. These east-west oriented basins are separated by major structural elements oriented in a north-south direction. In China, there are three major petroleum provinces, namely: the eastern China province characterized by its rifted basins; the western China province characterized by its compressional basins; and the central China province between the eastern and western China provinces. In the eastern China province, the Cenozoic and Mesozoic sediments were deposited on the pre-Sinian shield and in folded belts of different geological ages. In the western China province, because of the movement of the Indian plate, the basins were uplifted and grabens were formed in Cenozoic time. In the northern part of the western China province, oil has migrated several times, reservoirs were destroyed, and oil was degraded to heavy oil at the Himalaya stage.

Presently heavy oil has been discovered in 15 Chinese basins. The heavy oil reservoirs are distributed in Sinian to Tertiary rocks, but the majority of the reservoirs occur in rocks of Mesozoic and Cenozoic age. Most of the reservoirs are found at depths between 1000 - 1500 m, though some can be found as deep as 2000 m (Figs. 1 and 2). The definition for heavy oil adopted by this paper is that the specific gravity is greater than 0.935 and the viscosity is above 100 mPa.s. Heavy oil samples, collected from the northwestern Junggar basin, Bi-yang basin, Jiang-han basin, Huang-hua basin, Liao-he basin and the Ji-yang basin, were studied and samples from the Congo and Italy were used for comparison.

GEOCHEMICAL ASPECTS

Hydrocarbon Group.

Saturated and aromatic hydrocarbons comprise over 60% of conventional light and medium oils with a maximum value of 95% (Fig. 3), but are less than 60% in heavy oil with a minimum value of 20%. The asphaltene content is normally less than 5% in light and medium oils, but can be as high as 10 to 30% or even 50% in heavy oil. Figure 4 displays the relationship between the content of asphaltenes and the specific gravity of heavy oil.

Characteristics of Alkanes in Heavy Oil.

The distribution of alkanes in an oil reflects the nature of the source rocks, the depositional environment, and the maturity level of the source rocks. The distribution of the alkanes can be used to classify the oil. On the other hand, the distribution of the alkanes are affected by the thermal alteration, migration, the conditions for accumulation, by meteoric water, and by biodegradation. Some heavy oils from the eastern China province show that the alkanes are predominated by isoprenoid alkanes with high peaks of pristane and phytane, but the steranes do not show evidence of biodegradation (Fig. 6).

■ Biodegradation.

The distribution of steranes and terpanes allows us to trace the nature of the source rocks and to measure the maturity level of the oil because of the resistance of these products to biodegradation.

■ Maturation indices.

The heavy oil samples from Emerande of Congo, and Sarago Mare of Italy (Connan and Coustau, 1984) and from the Junggar, Bi-yang, Jiang-han, Liao-he, Ji-yang, and Da-gang basins were used for calculation of the maturation indices defined as follows:

$C_{29}\ \beta\beta//\ (\beta\beta+\alpha\alpha)$ (1)

$C_{29}\ 20S/(20S + 20R)$ (2)

Table 1 lists the values of the two indices. The heavy oils from the Bi-yang, Jiang-han, Liao-he, Huang-hua and Ji-yang are immature, whereas the heavy oils from the Junggar basin and Congo are mature. The maturity level of the heavy oil from Italy ranges from immature to mature.

■ Distributions of Terpanes and Hopanes.

Heavy oils from the northwestern Junggar, the Huang-hua, the Do-ying, and the Ji-zhong basins contain demethylated pentacyclic hopanes, whereas heavy oils of some samples from the Junggar basin contain a series of 25-norhopanes (C_{26}, C_{28}-C_{34}), that is, hopanes missing the methyl at the A/B ring junction at the C10 position (Fig. 5). The 30-norhopanes are the first to be biodegraded, but detectable traces of demethylated hopanes, tricyclic terpanes (C20-C30) and tetracyclic terpanes (C24) are present. The characteristics of the last two components on the gas chromatogram is m/e 177 rather than m/e 191. The fact that tricyclic and tetracyclic terpanes appear after the pentacyclic terpanes indicates that tricyclic and tetracyclic terpanes are more resistant to biodegradation.

■ Order of Biodegradation.

According to the studies by Seifert and Moldowan (1979), Philp (1983) and the samples from the northwestern Junggar basin, the order of biodegradation may be listed from beginning to end as follows: n-alkanes, isoprenoids, bicyclic sesquiterpanes, regular steranes (20R, 20S), pentacyclic triterpanes, tricyclic terpanes, rearranged steranes, 25-norhopanes, 25,30-bisnorhopanes, $C_{24}H_{42}$ tetracyclic terpanes, 17(α)(H)-22,29,30 trisnorhopanes (Tm) and gammacerane. Based on the orders of biodegradation, heavy oils in China can be classified into four catagories: slightly, moderately, heavily and very severely biodegraded heavy oils.

(1) Slightly biodegraded. N-alkanes are partially removed, and the relative percentage of the isoprenoid alkanes increases. The heavy oil from Liao-he is an example (Fig. 6).

(2) Moderately biodegraded. N-alkanes have been removed completely, isoprenoids are partially or completely destroyed, but steranes and terpanes are not affected (Fig. 7).

(3) Heavily biodegraded. Isoprenoids have been completely removed. Bicyclic sesquiterpanes (C_{14}-C_{16}), regular steranes, and pentacyclic triterpanes are biodegraded, and consequently, the relative content of rearranged steranes, pregnanes, tricyclic triterpanes and tetracyclic terpanes increases. The heavy oil from the Zhong-jian of the Junggar basin is an example.

(4) Very severely biodegraded. N-alkanes are completely removed. All steranes and terpanes are biodegraded, except gammacerane. New products are generated. The Sha-giu-he area of the Junggar basin produced this type of heavy oil (Fig. 9).

■ Classifications of Heavy Oils.

The heavy oil from the lower Tertiary formations (=2000 m) is moderately biodegraded and immature (Shi, 1982; Fu and Jiang; 1985; Huang, 1984). Furthermore, if Index 2 and the degree of maturation are combined as criteria for classification of heavy oil, then the oils from the Bi-yang basin and the Shu-yi area of the Liao-he basin belong to immature heavy oil; oils from the Gao-sheng area of Liao-he basin, and the Jiang-han basin belong to the low mature oil; the oils from the northwestern Junggar basin, the Gao-shan-pu area of the Huang-hua basin belong to very mature oils. The heavy oils from Congo belong to low mature oil, whereas oil from Italy is marginally mature (Fig. 10). According to the degree of maturity level and biodegradation, the heavy oils from China can be classified into any one of the classes as listed in Table 2.

GEOLOGICAL ASPECTS

Geological Setting.

The reservoirs are made up of coarse-grained sandstones of continental origin and are at a depth less than 2000 m. The sandstone contains a clay matrix of 10 to 15% with high porosity (30 to 35%), and high permeability (0.3 to 2.0 mm^2). The oil saturation of the reservoirs is low and is related to the content of the matrix. If the reservoirs consist of more than 30% matrix, then they do not contain oil. If reservoirs are fine- to coarse-grained sandstones with a matrix of 10 to 15%, then the reservoirs are saturated with oil (60 to 70%) (Fig. 11). Reservoirs which have matrix between 15 to 30% have low oil saturation. Under the same reservoir conditions, the oil saturation for heavy oil is lower than that of light oil.

The late Tertiary tectonic activity caused a major migration event. There were two types of migration: migration along faults, and migration along an unconformity. These two types of migration caused the separation of light oil from heavy oil and also the biodegradation along migration paths.

Figure 12 demonstrates the changes in hydrocarbon components along the migration path. Beginning at the Gang-dong oil field located in the area of the source rocks, the oil has not been biodegraded. While the Gang-xi and Yang-er-zhuang oil fields are located in the vicinity of source rocks, their oil has been slightly biodegraded (n-alkanes have been completely removed and isoprenoid alkanes increased relatively). The Yang-er-mu and the Kong-dian oil fields are situated at a greater distance from the source rock, so the oil was severely biodegraded, the pristane and the phytane were partially biodegraded.

Formations of Heavy Oil Reservoirs and Their Characteristics.

Heavy oil reservoirs were formed by a sequence of processes such as tectonic uplift, biodegradation, flushing by meteoric water and oxidation by air. We shall now discuss the formation of the heavy oil reservoirs and their characteristics.

(1) Flushing by meteoric water and oxidation by air. Heavy oil from the Zao-yuan oil field is an example of this type. This oil field is located at the structural high on the southern Huang-hua basin. Producing Eocene sandstones are conglomeratic sandstones deposited in diluvial fans. The sandstones have a porosity of 24 to 26%, and a permeability of 0.2 to 2.0 mm^2. The heavy oil varies from slightly to heavily biodegraded. The properties of producing formations are different in each faulted block. The heavy oil from the faulted blocks located at a structurally low level has been slightly biodegraded, and was rich in n-alkanes, pristane and phytane; the specific gravity ranged from 0.9187 to 0.9260, and the viscosity ranged from 525 to 580 mPa.s. The oil which occurred within the same faulted blocks, but at the structural highs has been slightly to moderately biodegraded; n-alkanes were partially removed; specific gravity was 0.9450; and viscosity was 15505 mPa.s. The oil from the Sha-xi of the same basin have the same distributions of n-alkanes, steranes and terpanes as the oils from the structurally low areas, but the Sa-xi oil has relative high compositions of steranes C29 (20R) and low in (20S). The oil is low maturity and has been slightly biodegraded.

The history of the formation of the heavy oil can be reconstructed as follows(Fig. 13): The Kong-dian anticline was formed at Late Eocene. At this time, the source rock, Kong II member, was buried at a depth of 2600 - 2800 m, and was at the oil window. In Late Oligocene, the anticline was uplifted and its cap rock was partially eroded. The capability of the trapping mechanism has deteriorated, therefore, the oil from this oil field have very low gas/oil ratios(GOR), 8 - 10 m^3/ton with high resin and asphalt content. This is in contrast to the oil occurring in the structurally low areas where the GOR is 50 m^3/ton.

(2) Along the margin of the basin, oil was oxidized by air and biodegraded. The properties of the oil changed vertically. For example, the Karamay-xiazi-jie play of the Junggar basin has five producing zones distributed in Carboniferous, Carboniferous - Permian, Triassic, Jurassic, and Cretaceous formations. The Upper Jurassic and Cretaceous formations produce heavy oil and exhibit a fineing upward sequence. These sandstones have high porosity (30 - 32 %), and high permeability (4 - 7.5 mm^2). The oil was generated in the depression near Malas lake. The age of the source rock is Carboniferous-Permian. Oil and gas have migrated along an unconformity surface and have accumulated in different types of trap. Accumulations in younger formations usually occur where leaks link them to older traps. Heavy oil occurs along the edge of the basin, where light oil is horizontally imbricated on the heavy oil reservoirs.

Another example of oxidation is the Lower Jurassic, Lower and Middle Triassic and Permian-Carboniferous reservoirs which have properties such as low specific gravity, high wax content, and high initial GOR. On the other hand, the Upper Jurassic and Cretaceous reservoirs, found at a depth of less than 500 m, have properties such as high specific gravity and viscosity, low wax content, and low initial GOR with evidence of biodegradation (n-alkanes and isoprenoid alkanes have been destroyed). Biomarkers such as steranes and terpanes were not biodegraded. The content of rearranged steranes increased. Stigmastanes (C_{29},5 α 14 α ,17α ,20R) and ergostanes (C28,5 α ,14 α ,17α, 20R) have been essentially removed. Oils occurring along the edge of the basin were heavily biodegraded with n-alkanes and isoprenoids having been completely removed and bicyclic sesquiterpanes (C_{14}-C_{16}), regular steranes and pentacyclic triterpanes altered.

(3) Heavy oil formed by secondary migration. This type of heavy oil is widely distributed in rollovers and drape anticlines occurring in Tertiary basins. The coarse-grained fluvial sandstones have high porosity and permeability. Oils have migrated along the unconformity surfaces and faults into the Tertiary structures.

The Gang-dong heavy oil field (Fig. 15) occurs in a rollover anticline situated at a large scale faulted block. Producing horizons are Tertiary conglomeratic sandstones. The fluvial sediments were buried at a depth of less than 2000 m. The sandstones with minor cementation have a porosity over 30% and a permeability of 1.0 mm^2. Oil and gas have migrated vertically. The properties of the oil vary from bottom to top of the stratigraphic section as mineral contents of the formation water decrease toward the younger formations. Methane content, specific gravity, viscosity, resin content, and biodegradation of the oil increase towards younger formations.

(4) Reaction with aquifers. Oil in the reservoirs reacted with aquifers and became heavy oils. Specific gravity decreases towards the younger formations. Usually, a gas cap exists.

The Gu-dao heavy oil field shown in Figure 16 is an example. This oil field is located at the eastern edge of the Zhan-hua basin. The Tertiary sediments were folded over the Paleozoic uplift. The anticline produced by this setting has a flat top with steep sides. The sandstone of the Guan-tao group unconformably onlaps on the Paleozoic limestone. Depths of reservoirs range from 1160 to 1300 m. The heavy oil was formed by the reaction of oil and the aquifer underneath. The Guan-tao group is fluvial in origin, occurs at a shallow depth, and consists of friable sandstone with porosity of 28 to 32%, permeability of 0.5 - 2.4 mm^2, matrix content of 9 - 12%, and carbonate content of 0.3 - 0.7%. The oil is over saturated with a specific gravity of 0.935 - 0.990, viscosity of 250 - 5700 mPa.s, resin content of 27 - 54.2%, asphaltenes of 6.6% and wax content of 4.9 - 7.2%. Oil properties vary vertically from light oils lower down into heavier oils. Oil characteristics vary from shallow to deep along the same horizon. For example, in the 44 horizon; the specific gravity varies from 0.9457 to 0.9784, and the viscosity varies from 247 to 1931 mPa.s with small gas caps at the top of the anticline. Light components of the oils dissolved into aquifers and were flushed from the reservoir and therefore, the heavy oil was formed.

CONCLUSIONS

- ☐ *(1) The occurrence of tar sands and asphalt at the surface show very severe biodegradation. Heavy oil reservoirs occur at 1000 m or less, and show moderate biodegradation, whereas reservoirs at depths between 1000 to 2000 m show slight biodegradation.*
- ☐ *(2) Reservoirs are controlled by structures. Drape anticline reservoirs occur at the edge of a basin, onlap reservoirs occur at the steep slope, and unconformity traps on the gentle slope.*
- ☐ *(3) Usually, light oil occurs at the centre of a basin and heavy oil occurs along the edges of a basin. Vertically, light oil occurs in the deeper horizons, and heavy oil occurs in the shallow horizons.*

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Table 1
Data for Steranes from China

Area	Well	Depth(m)	Stratigraphic horizon	Steranes Index 1	Steranes Index 2
Junggar basin	Feng-cheng asphalt	164-183	K	0.538	0.617
	9th dist.1		J_3	0.522	0.613
Bi-yang	Bi 103	1966.5-1971.61	E_{h3}	0.190	0.180
Jiang-han	Wang 30	737	E_{q1}	0.386	0.419
Huang-hua	Yang 14-14	1220-1430	E_{s1}	0.393	0.392
	Gang 1	1801-1821	E_{m1}	0.207	0.304
	Gao 31	1836-1845	E_{m1}	0.508	0.517
Liao-he	Gao 2-1-061	1624.5-1668.9	E_{m3}	0.308	0.227
	Shu 1-41-50	439.5-586	E_{m4}	0.254	0.242
Ji-yang	Bo 107	1193.4-1305	N_g	0.330	0.380
	Nian 4	1368.4-1369.4	E_{m1}	0.090	0.190
Emerande Congo	E_{mm} 103	423.5-426	Form. II	0.213	0.426
Italy	Sarago Mare	1441-1527	Miocene	0.622	0.412

Table 2
Classification Scheme for Heavy Oils in China

	Slightly	Moderately	Heavily	Very Severely
Immature[1]				
Low mature	2	3	4	5
High mature	6	7	8	9

2: Slightly biodegraded and low mature heavy oil
3: Moderately biodegraded and low mature heavy oil
4: Heavily biodegraded and low mature heavy oil
5: Very severely biodegraded and low mature heavy oil
6: Slightly biodegraded and highly mature heavy oil
7: Moderately biodegraded and highly mature heavy oil
8: Heavily biodegraded and highly mature heavy oil
9: Very severely biodegraded and highly heavy oil

Figure 1

Distribution of the Heavy Oils in the Mesozoic Chinese Basins. A: Heavy Oil; B: Tar Sand; C: Asphaltenes; D: Major Petroleum-bearing Basins – 1: Junggar Basin; 2: Tarim Basin; 3: Qaidam Basin; 4: Er-ling Basin; 5: Song-liao Basin; 6: Shaa-gan-ning Basin; 7: Bo-hai Basin; 8: Su-bei Basin; 9: Dong-hai Basin; 10: Si-chuan Basin; 11: Zhun-jiang-kou Basin.

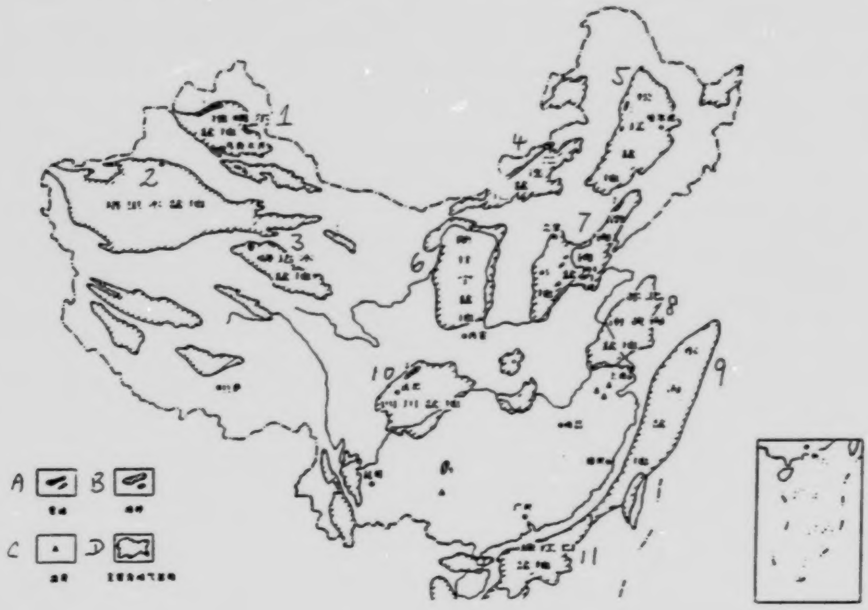

Figure 2

Histogram Showing the Percentages of the Heavy Oils (In Term of the Total Reserves) According to their Depths (left) and the Ages (right) of the Heavy Oil Reservoirs in China

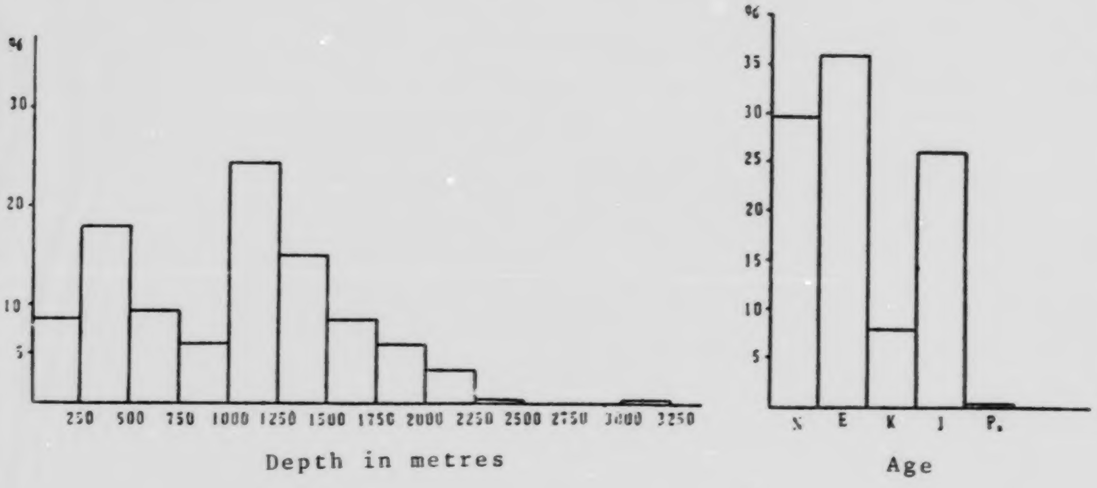

Figure 3
Ternary Plot for the Compositions of the Heavy Oils

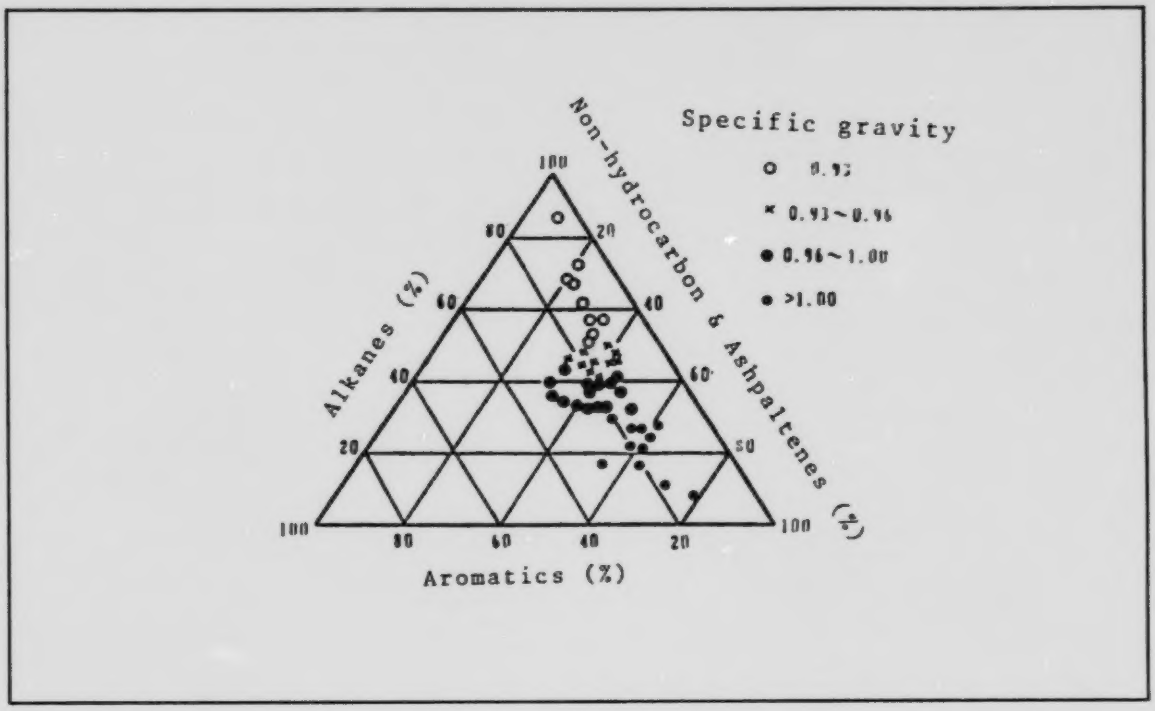

Figure 4
Cross Plot Between the Specific Gravity and Asphaltenes of the Heavy Oil. 1. Well Feng-qian 25, Xin-jiang; 2: Well 9147, Xin-jiang; 3: Well Yang 14-14, Da-gang; 4: Well Ya-32, Jiang-han; 5: Well Gao-sheng 753, Liao-he; 6: Well Wang 30, Jiang-han; 7: Well W-1-33-12 Jiang-han

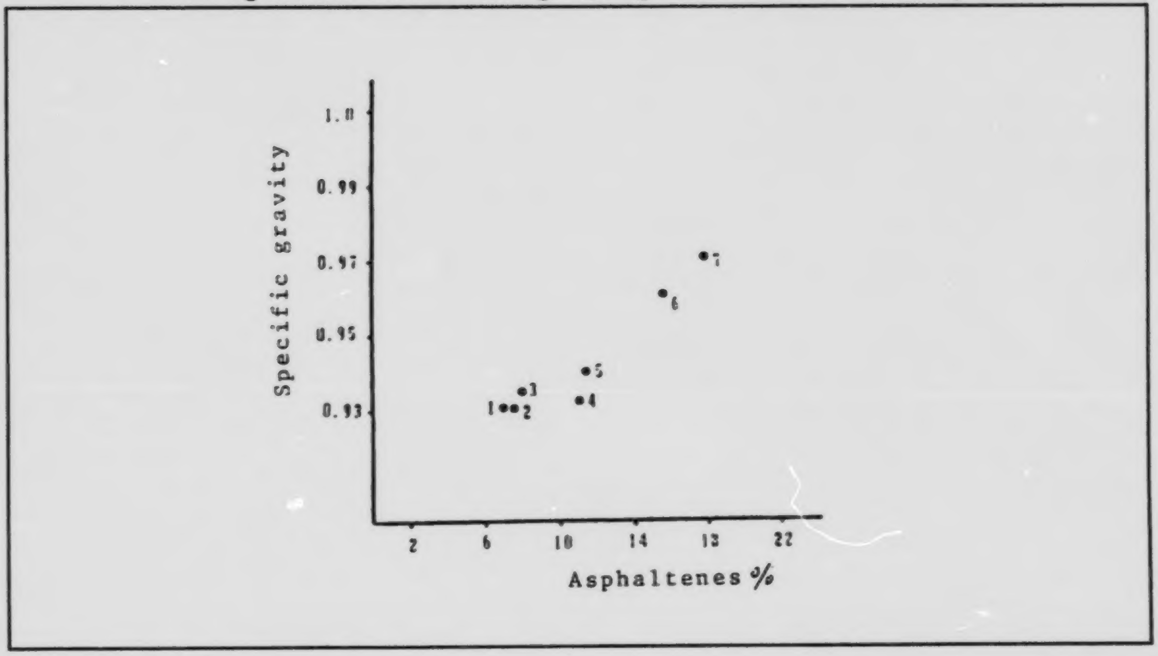

Figure 5
Gas Chromatograms for the Tricyclic and Tetracyclic Terpanes, pentacyclic Hopanes and their Demethylated Products of the Heavy Oils from the Karamay Oil Field

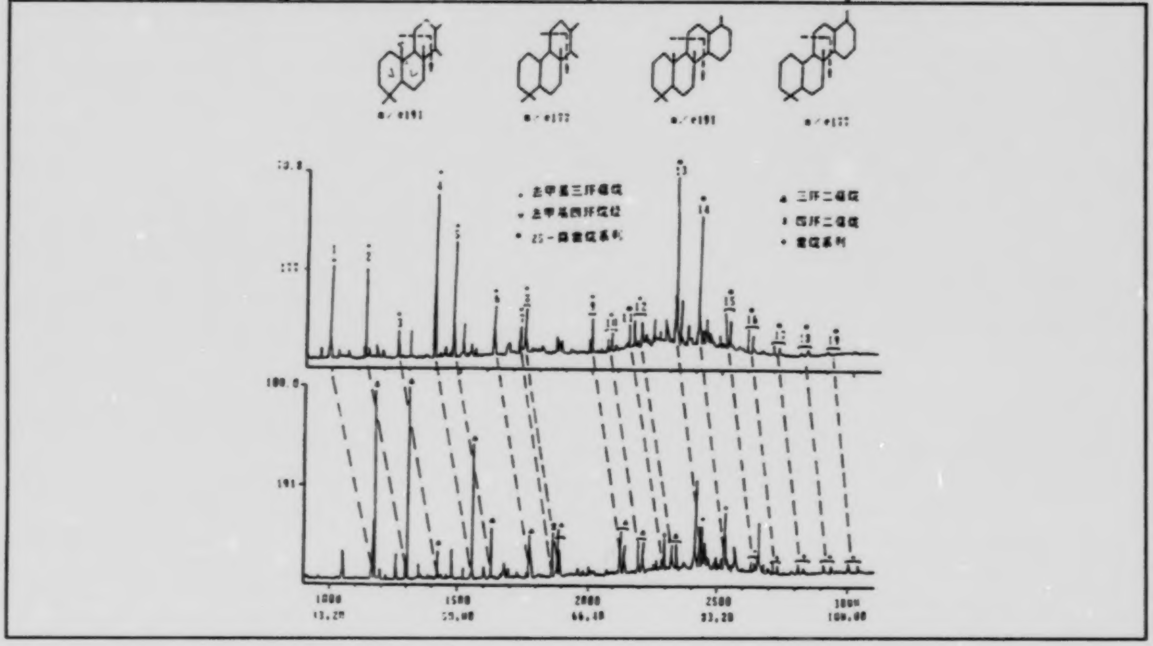

Figure 6
Gas Chromatogram Showing Slight Biodegradation for the Saturated Hydrocarbon from Liao-he

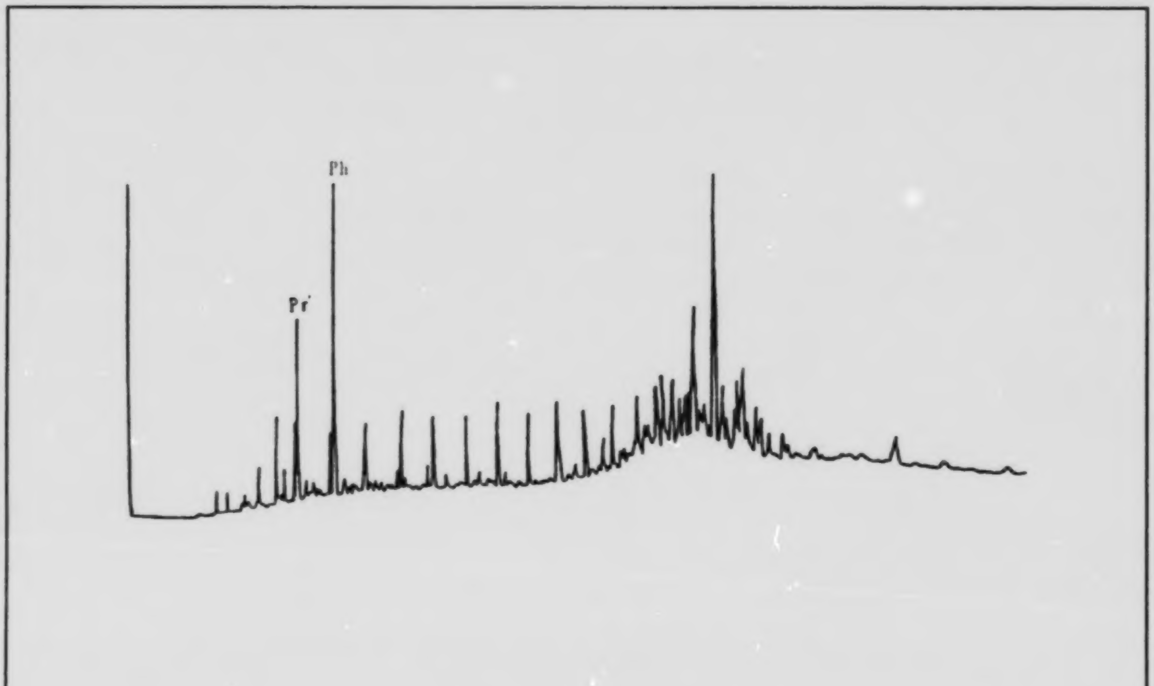

Figure 7
Gas Chromatograms Showing Moderate Biodegradation for the Heavy Oils from Black Oil Mt, Junggar Basin

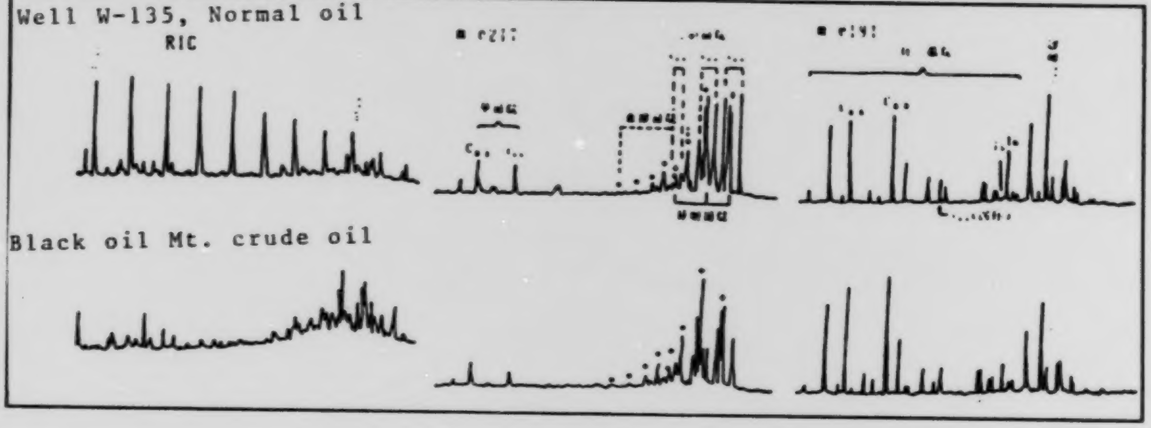

Figure 8
Gas Chromatograms Showing Heavily Biodegraded Heavy Oils from the Junggar Basin

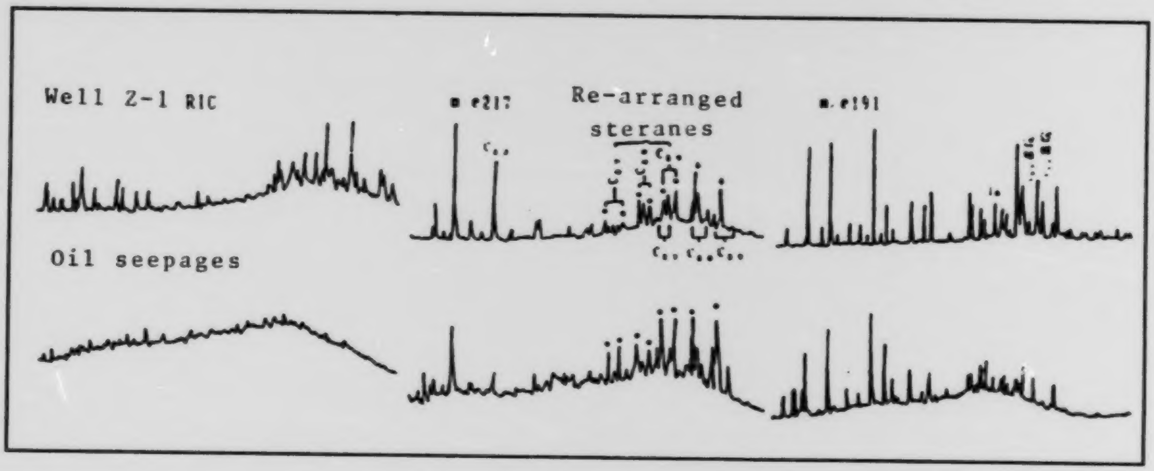

Figure 9
Gas Chromatograms Showing Very Severely Biodegraded Heavy Oils from the Hunggar Basin

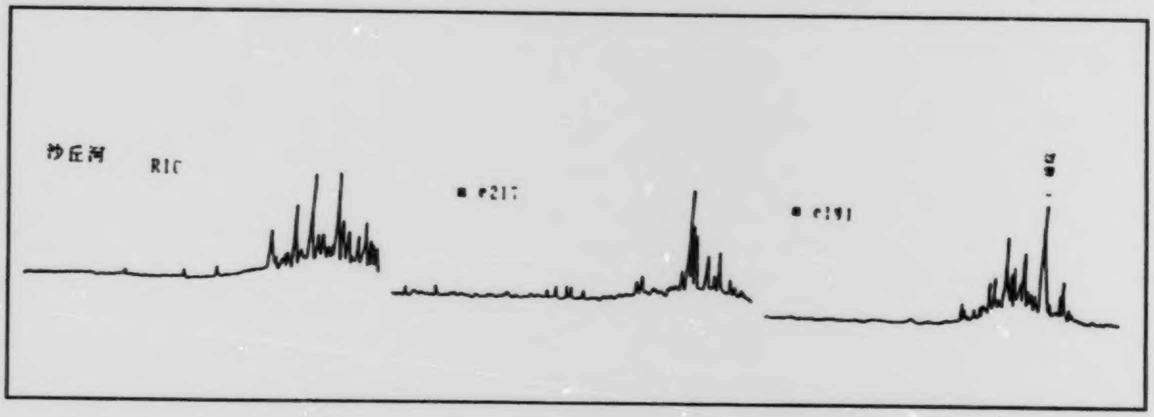

Figure 10
Cross Plot Between the Index 1 and Level of Maturity - A Scheme for Heavy Oil Classifications. 1: Junggar Basin; 2: Italy; 3: Congo; 4: Liao-he; 5: Huang-hua; 6: Bi-yang; 7: Jiang-han; 8: Ji-yang.

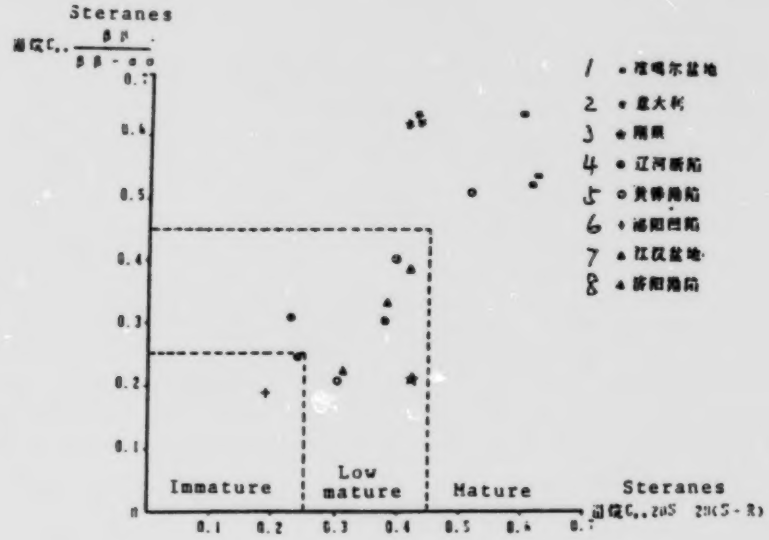

Figure 11
Cross Plots Between Heavy Oil Saturation and Porosity (upper) and Permeability (lower). 1: Well G-205; 2: Well C-2; 3: I-Heavy Oil, II-Light Oil; 4: Well G-3-3-05; 5: Well B-1-6-37; 6: Well Y-1

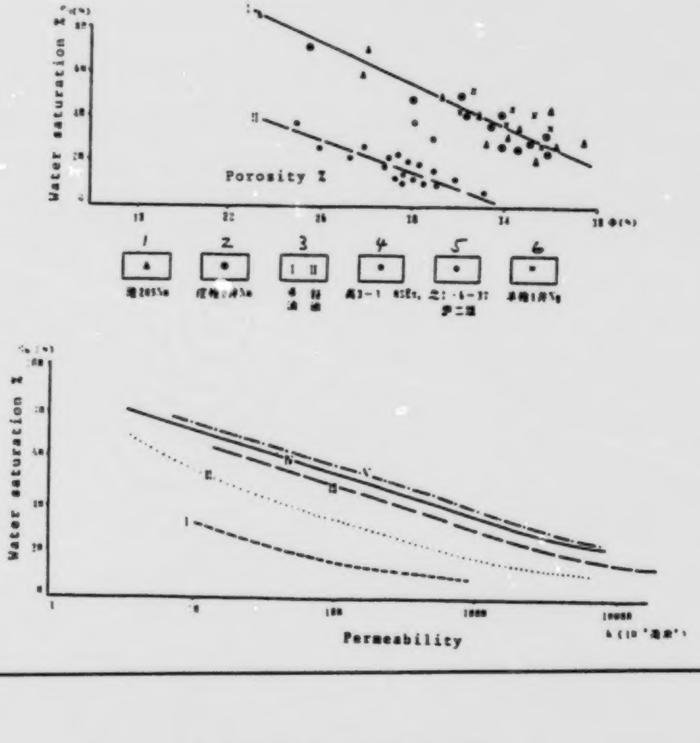

Figure 12
Map Showing the Relationships Between the Degrees of Biodegradation and the Distance of Migration in the Vicinity of Gang-dong Oil Field. 1: Heavy Oil Fields; 2: Early Tertiary Oil Fields

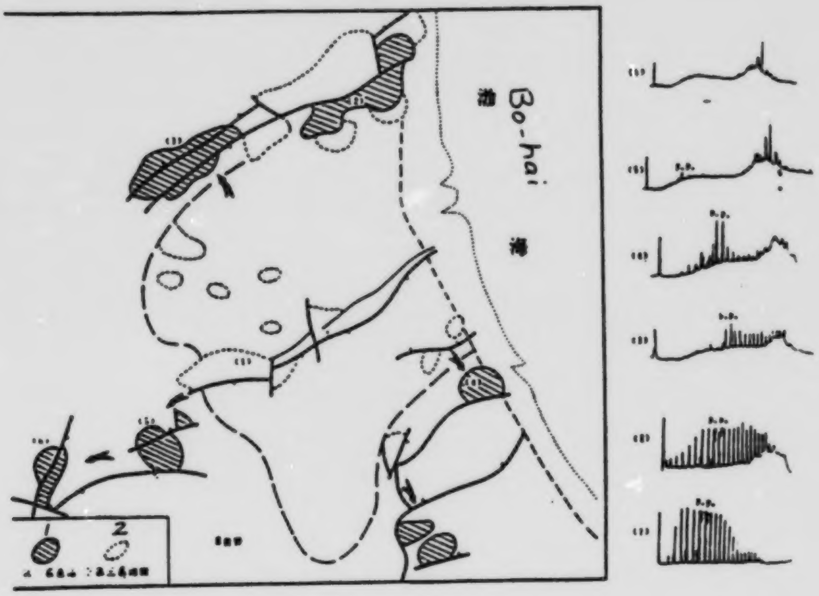

Figure 13
The Trap Types and the Degrees of Biodegradation in the Wang-guang-tun Oil Field. 1: Anhydrite; 2: Heavy Oils; 3: Light Oils

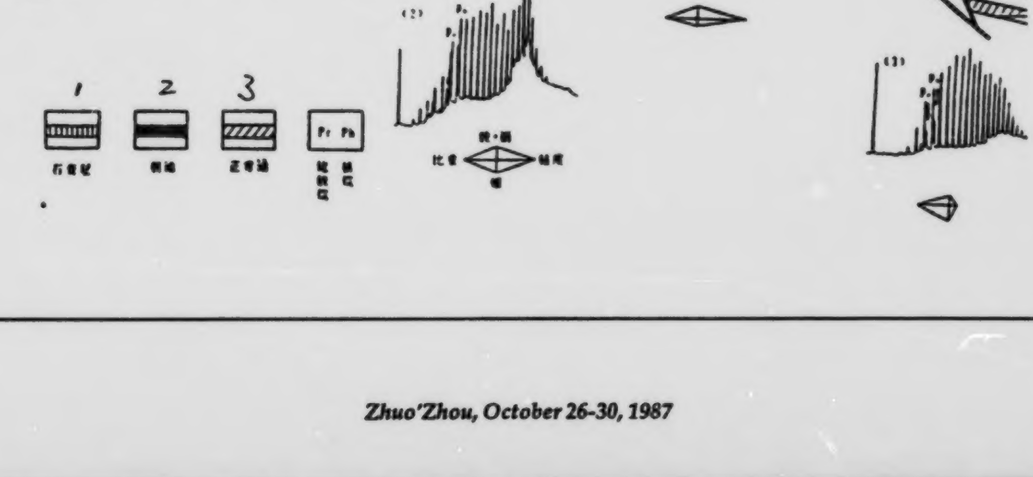

Figure 14
The Trap Types and the Gas Chromatograms of the Biodegradation from the Northwestern Junggar Basin. 1: Heavy Oils; 2: Light Oils; 3: Surface Asphalts

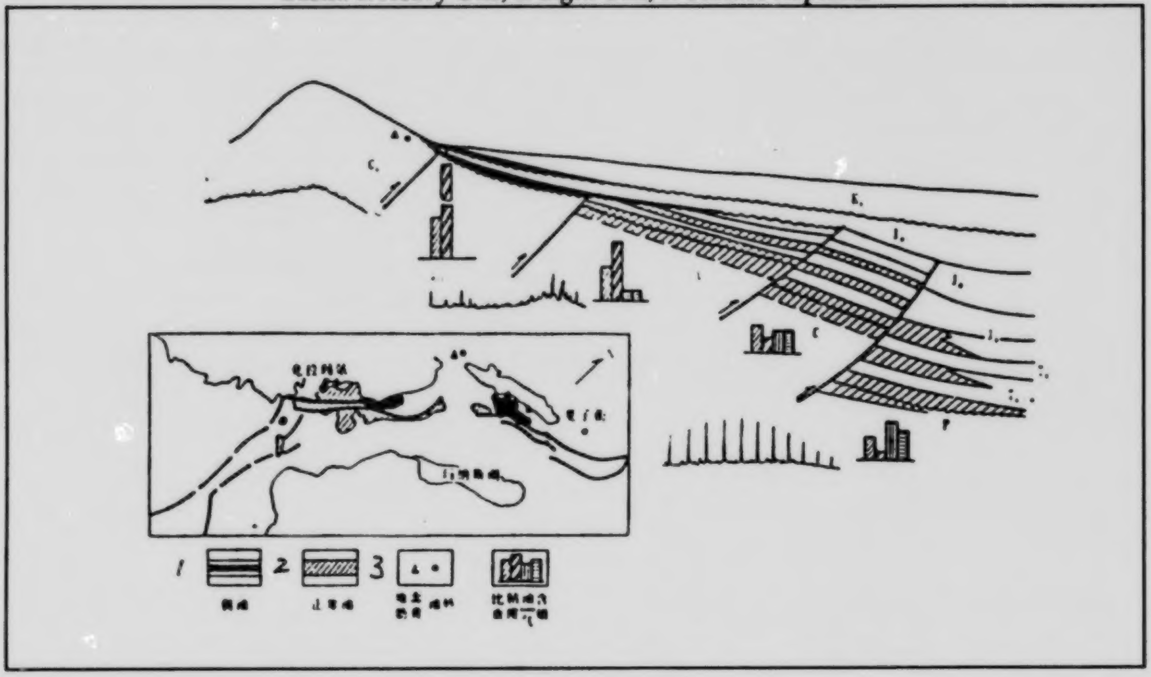

Figure 15
The Trap Types and the Gas Chromatograms for the Gang-dong Oil Filed. 1: Resin and Asphaltenes; 2: Specific Gravity; 3: Viscosity; 4: PAraffin Content

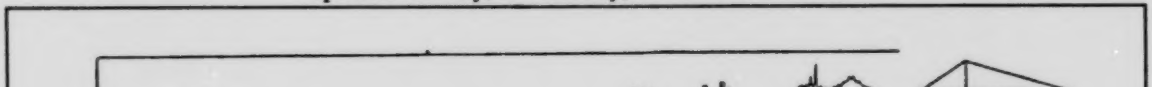
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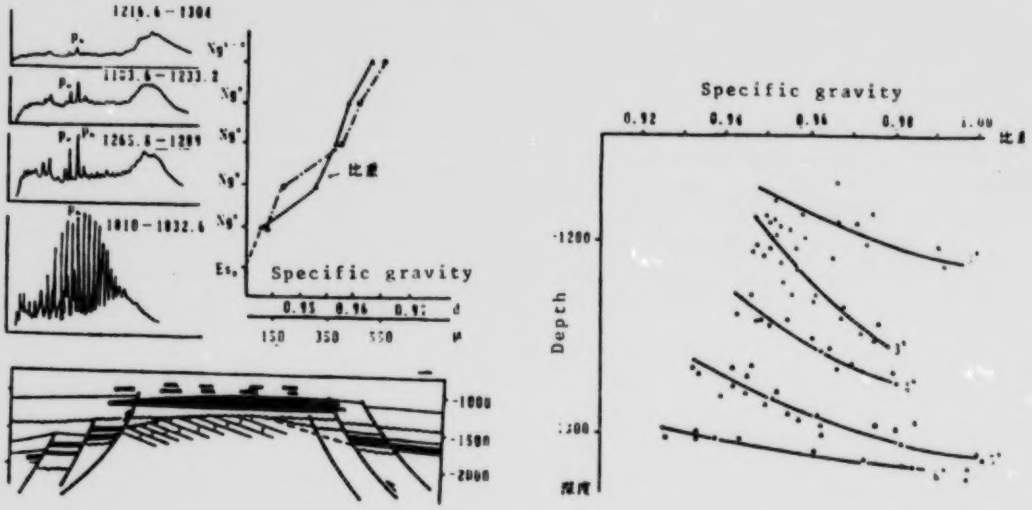
Figure 16
The Trap Types, the Gas Chromatograms, and the Relationships Between the Specific Gravity and Depth for the Gu-dao Oil Field



2

AOSTRA HEAVY OIL AND BITUMEN IN SITU PILOTS

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ABSTRACT

Alberta's bituminous and heavy oil deposits are located in a broad arc extending across the northern part of the province and down the eastern side a distance of some 1200 km from Peace River in the northwest to the Suffield block in the south. This area contains one of the largest hydrocarbon deposits in the world measuring perhaps as much as 400 billion m^3 of reserves in place.

One of the principal reasons for the formation of AOSTRA was to encourage the development of technology which would enable commercial exploitation of this immense resource.

This paper starts in the northwest and follows the resource through to the southeast and in the process outlines the geological and petrophysical characteristics of each deposit and the corresponding recovery processes which have and have not been successful with emphasis on AOSTRA's pilots and experience.

INTRODUCTION

Alberta's bituminous and heavy oil deposits are located in a broad arc (Figure 1) extending from the Peace River deposit in the northwest to the Suffield heavy oil deposits in the southeast, a distance of some 1200 km. As indicated in Table 1, total reserves in these deposits are estimated at 400 x 10^9 m^3 of hydrocarbon in place with the largest deposits being those of the carbonates (~125 x 10^9 m^3) and the Athabasca bituminous sands (~151 x 10^9 m^3).

Across the northern part of the province, the deposits are primarily bituminous with API gravities less than 12 and viscosities so high at reservoir conditions that there is essentially no primary production. Along the eastern side of the province, API gravities are typically in the 15 to 18 range and some primary production does occur (~5% primary with another 3 or 4% by water flooding). The pays, however, are usually thinner and are often underlain by water.

The geological and petrophysical properties of the deposits vary considerably and this has led to a variety of recovery schemes, each tailored to a specific deposit. In some instances major progress has been made with extensive commercial exploitation underway while in others considerable technological development must occur before the resource can be successfully tapped.

The deposits and the progress made on each is now reviewed moving around the arc from the northwest to the southeast.

PEACE RIVER

The Peace River deposit consists of lower Cretaceous sands of the Blue Sky and Gethering formations. These sands lie unconformably on Devonian limestone of the Mississippian Debolt formation and are capped by Cretaceous Clearwater shales. The sands pinch out to the northeast against a high in the Devonian unconformity. They dip slightly (~2m/km) to the southwest to an eventual oil water contact. The sands were deposited along the shores of a transgressive sea advancing from the north and northwest. These sands are thus a single upward fining sequence with highest porosity and permeabilities near the base. There is also considerable lateral continuity with good correlations between wells, even on large spacings. These unconsolidated or slightly consolidated sands contain large amounts of amorphous silica and thus are reactive to high pH >8 solutions. The underlain Debolt formation often contains water-filled permeable zones. The deposit lies some 500 to 600 m deep and contains a 9° API gravity asphaltic crude with a viscosity of ~200,000 m•Pa•s at reservoir temperature of 17°C. There is no primary production.

Figure 2 indicates the variability in petrophysical properties for a typical cross-section through the deposit. It can be seen that permeability and water saturation are much higher at the base of the deposit. This characteristic has led to the development of the "Pressure Cycle Steam Drive" which has been demonstrated to be so successful in recovering hydrocarbons from this deposit. In this process, hot water and steam are injected into the basal, high water-saturated sands and hot communications are achieved across the base of the deposit to the production wells which have been preheated by steam stimulation. Pressure is then built up in the reservoir by high steam injection rates combined with limited production. This is followed by a pressure depletion phase or blowdown in which production is increased and injection reduced. The cycle is repeated several times forcing the heat to rise up the reservoir and bitumen to flow down and to the production wells. Ultimate recovery is anticipated to be in excess of 50% with SOR <4 and CDOR >10.

AOSTRA (50%), Shell Canada Resources Limited (18.75%), Shell Explorer Limited (18.75%), and Amoco Canada Petroleum Company Limited (12.5%) conducted a 41-well (seven seven-spots) pilot of this process in the 1973-1987 period. The success of this pilot led to Shell Canada Resources going ahead with a commercial opera tion designed to produce 1500 m^3/day of bitumen. Steam injection into this commercial operation first got underway in the fall of 1986 and marked the first commercial recovery from the Peace River deposit.

THE CARBONATES

Throughout north central Alberta is a large triangular area of Devonian limestone (Figure 3) which is impregnated with bitumen. Total reserves in this area may be as much as 250 billion m^3 although current estimates based on limited drilling are at 125 billion m^3.

The Paleozoic formations of the "carbonate trend" are primarily Upper Devonian and Mississippian in age. These formations dip gently to the west, are truncated up-dip by a regional unconformity, and are overlain by relatively flat-lying Cretaceous clastic sequences (Figure 4). Bitumen, similar in chemistry, viscosity, and origin to that within the younger Cretaceous oil sands, is trapped in porous limestone and dolostone horizons beneath the subcrop erosional margin.

As with most carbonates, porosities in general are lower and heat capacities higher (~15%) than with unconsolidated sands, hence, interest has primarily focused along the subcrop of the Devonian unconformity where porosities and, hence, bitumen content are highest (Figure 5). This region represents a typical receding sea environment grading from marine at the base to intertital at the top. The zones, such as the Upper Grosmont 2, are typically confined on the top and bottom by shale. Working along the unconformity does however present difficulties since erosion features such as sink holes and karsting often lead to a complex geology and the loss of reservoir confinement.

The bitumen in pregnated carbonates, as with many carbonates, often contain a duel porosity and permeability system; a intergranular porosity within which most of the bitumen is found and a regular-fracture system with very high transmissibility. This feature, if present in the right proportions and relationship to each other, provides an ideal means of communicating with the reservoir. Injected agents, such as steam, can flow through the fracture-vugular porosity system to a point in the reservoir where they can interact with the bitumen in the intergranular porosity, lower its viscosity and cause the bitumen to flow via the fracture-vugular porosity system to a production point.

AOSTRA has worked with Union Oil Company and Canadian Superior Oil and Gas on a number of pilots in the Grosmont II and III formations along the subcrop trench. These pilots have tried a number of technologies with mixed success. The use of steam drive or combustion drive was found to be unsuccessful. However, where the geology was amenable, the use of steam stimulation was found to be very effective, giving producing rates as high as 70 m^3/day. Steam injection was well below fracture pressure and was believed to primarily enter the high vulgur/fracture porosity permeability zones and these in turn transmitted the heat to the intergranular, high bitumen saturated zones.

Work on these pilots has been temporaily suspended pending further geological evaluation, the provision of an all weather access road to the area (currently only accessable by a winter ice road) and improvement in oil prices.

WABASCA

The Wabasca Oil Sands Deposits is located in north-central Alberta, west of the large Athabasca Deposit. Within the Wabasca Deposit, oil sands are found in several stratigraphic horizons: the three Grand Rapid Formation sands and the McMurray/Wabiskaw interval sands. This is the smallest ($\sim 7 \times 10^9 m^3$) of the four major oil sands deposits and the least exploited.

Overburden over the deposit ranges from 100 m in the north to in excess of 600 m in the south. The resources are contained in three sands: the upper A sand is estimated to contain 4.1×10^9 m^3 of oil in place with an average pay zone of 9 m; the middle B sand is estimated to contain 1.4 x 10^9 m^3 of oil in place with an average pay zone of 5 m; and the lower C sand, although not as well delineated as the other two sands, is estimated to contain 1.2 x 10^9 m^3 of oil in place with an average pay zone of 6 m. Porosities in the sands range from the high 20's to the low 30's with average bitumen pore volume saturation around 50 percent. The gravity of the crude ranges from 5-10 API and there is no primary production.

In addition to the Grand Rapids formations there is also oil saturation in the lower members of the Clearwater formation. Here the deposit is small and pay thicknesses are thin (~4m), however, in selected parts of the formation the API gravity may go as high as 16 API.

Because of the thin pays and high viscosity of the crude, recovery (except for the higher gravity crude) has not been successful to date. The thin pays have made steam stimulation unprofitable while the high viscosity has made it difficult to conduct a forward combustion operation, since insufficient mobility could be maintained ahead of the combustion front to sustain injectivity or move the oil. In the higher gravity (16 API) portion of the Wabiskaw member of the Clearwater formation, it has been possible to conduct a successful forward combustion operation and an extensive pilot operation is underway.

ATHABASCA

The Athabasca Oil Sands Deposit is the largest of Alberta's oil sands deposits, with an estimated 151 x 109 cubic meters of oil in place. In the Clearwater and Athabasca river valleys where the overburden has been mainly eroded away, the oil sands is covered by <45 meters of unconsolidated glacial fill. In this area, which represents about 10% of the deposit, the rich deposits are being surface mined and the bitumen extracted by the hot water process.

Current production is about 30,000 m^3/day. The balance of the deposit, however, where overburdens range up to 750 m, represents a formidable challenge to in situ recovery methods. The high viscosity (>1,000,000 m•Pa•s at reservoir conditions) of the oil and lack of formation energy, combined with the most complex geology of any of the deposits, have so far resulted in very limited success at the field pilot stage.

The bulk of the reserves of the Athabasca Deposit are contained within the Lower Cretaceous McMurray formation, a dominantly continental sequence of unconsolidated sands and shales overlying an unconformity surface of Devonian limestone. The thickness of the formation, a function of the relief on the underlying unconformity, varies from 150 m in the centre of the depoosit to zero in the west where it pinches out against a paleotopographic ridge of Devonian limestone.

The McMurray Formation is overlain by the marine Clearwater Formation. Compared to other Alberta oil sands deposits, the sediments of the Athabasca Deposit have a very uniform, mature mineralogy. Sands in the McMurray formation consist of 91 to 99 percent quartz and a few percent each of feldspar and rock contrast to the other oilssands deposits. In the overlying Clearwater Formation, sediment of volcanic origin makes an appearance, signaling a change in source area from the east to the cordillera region in the west.

The McMurray deposit is predominantly a fluvial deposit representing an upward fining sequence resulting from a gradual encroachment of the Boreal Sea. In most areas it can be divided into three zones each of which is upward fining.

The lower McMurray fills in the lows on the Devonian unconformity and is present where the total formation thickness is >60 m. It consists of medium to course grain sand in thick fluvial sequences 2 to 20 m thick dominated throughout by large-scale trough cross bedding. Porosity (>30%) and permeability (4 darcies) are high as is bitumen saturation (>80%) above the oil/water contact.

The middle McMurray consists of 15 to 25 m of epsilon cross strata, normally in solitary sets, consisting of decimeter to meter thick couplets of sand/mud with depositional slopes of 8 to 12 degrees. Sands are highly porous with variable permeability and bitumen saturation.

The upper McMurray consists of flat laying beds overlaying the dipping epsilon cross-strata of the middle member. It is 10 to 15 meters thick and represents lagoonal and inter-tidal deposits of late McMurray time. The zone is very fine grained and argillaceous with often poor vertical permeability. Bitumen saturations is low and although absolute horizontal permeability is also low, the low bitumen saturation often leaves high horizontal relative permeability to water.

Because of the fluvial nature of the deposit, lateral continuity between wells at even short distances (<50 m) can not be achieved.

The complex geology of the McMurray formation, the low gravity (8 to 10 API) and high viscosity (>1,000,000 m.Pa.s) at reservoir conditions, the lack of reservoir energy (very little dissolved gas) and the high bitumen saturation of the most permeable sands (80%) have made in situ recovery from the deposit extremely difficult. A wide variety of recovery project have been tried from 1926 to the present and while a great deal has been learned, no commercial method of in situ recovery has yet evolved.

In 1976 AOSTRA joined with Amoco, PetroCanada, Suncor and Shell in a large demonstration test of a combustion recovery process which Amoco had pioneered and tested at a short well spacing and which had shown promise of being a successful recovery process for Athabasca.

The pilot, consisting of 9 five-spots, was designed to test a process which consisted of (a) fracturing horizontal at the base of the deposit to obtain communications; (b) injecting air above fracture pressure and initiating combustion in the fracture system and burning through to the production wells; (c) allowing the fracture system to plug with bitumen, refracturing at a higher level, and repeating the burning - healing-fracturing process several times until the reservoir was heated to an average of 100°C; (d) blowing down the reservoir through the production wells (first major bitumen production); (e) initiating a normal wet forward combustion process to recover up to 50% of the bitumen in place from the preheated reservoir.

While the process had worked for Amoco on smaller spacing, it did not operate successfully at larger (commercial) spacing. Fractures initiated at the base of the injection well climbed up the reservoir and intersected high lying transmiscible zones. Communications could not be sustained across the base of the deposit and hence the reservoir could not be preheated.

Another means of preheating the Athabasca reservoir so that recovery can take place is by electrical heating in which the oil sands become a resistor between two electrodes. These may be specially designed wells or an over-laying water zone and under-laying shale. Calculations of the energy required indicates that this could be an attractive recovery process.

In the period 1976 to 1982 PetroCanada conducted a pilot using the electrical preheat concept. While it was demonstrated that electricity could be used to preheat a reservoir and many technical problems were overcome, the cost of well completions, electrical isolation and safety factors was high.

A third recovery concept first pursued by shell and later by Fina, Texaco and Amoco in that order was to obtain a hot communication path (preferably at the base of the deposit) between the injector and the producer using a combination of hot water and steam and then recover bitumen from around this hot communications path in a modified steam drive process. Modifications to the steam drive process included interwell pressure cycling, as Shell has successfully done at Peace River, and/or the addition of agents such as CO_2, naphtha, air, bitumen etc. which would increase the pressure drop between the injectors and producers and thus increase recovery from the rest of the reservoir. Texaco in particular has successfully used this process to recover >55% of the bitumen in place from a small test area.

In 1979 Tenneco Oil and Mineral Ltd. and Canterra Energy Ltd. joined in conducting a modified steam drive pilot in the Athabasca deposit. In 1983 AOSTRA joined the piloting effort. Two pilots were developed as shown in Figure 6. In the A pattern, which was developed first, interwell communications was achieved in the bottom third of the deposit by horizontal fracturing (depth 250 m) and this was developed into hot communications by a combination of hot water and steam. Results from this pattern indicated that once hot communications was achieved, commercial acceptable production rates could be sustained by a normal steam drive process. The "B" pattern was undertaken to test methods of shortening the time until hot communications were achieved and to give a better estimate of the steam/oil ratio anticipated. The use of additives with the steam is also to be tested. Results from this pilot while encouraging are too early to be definitive.

In 1984 AOSTRA joined with Amoco and Petro-Canada to test the concept of developing hot communications followed by steam drive in a part of Athabasca somewhat deeper than at Kearl Lake. This small 4 spot pattern was to achieve hot communications by hydraulic fracturing followed by hot water and steam and then principle recovery by a modified steam drive process. The pilot is highly instrumented with tiltmeters, surface measurement surveys, and 3D seismic surveys to monitor all aspects of the process. Results to date are preliminary but do indicate the effectiveness of the survey methods in following the progress of the fracturing and recovery processes.

While great progress has been made in understanding in situ recovery from the Athabasca deposit and a near commercial process has been developed for the shallower deposits (<250 m overburden) no processes are available for the deeper deposits.

In deeper Athabasca one means of obtaining communications is by means of horizontal wells. While these can be drilled from the surface, these are often expensive.

An alternative is to put shafts to the base of the deposit and into the underlaying limestone. Horizontal tunnels are then completed in the Devonian limestone and wells drilled up into the overlaying oil sands. These wells may be vertical, slanted or horizontal.

In 1985 AOSTRA selected a site where the geology and petrophysics are as shown in Figure 7 and drilled two 3 meter shafts to Devonian limestone. These shafts were lined and equipped and then ~800 m of unlined horizontal tunnels 4 m x 5 m dug from the base of the shafts. A drilling rig was broken down into 16 parts, reassembled at the base and used to drill a number of wells up into the oil sands and horizontally along the base of the deposit (Figure 8). These wells were drilled in pairs with one well ~3 meters above the other and a horizontal spacing between the pairs of ~25 meters. Recovery is to be by means of a gravity drainage process as depicted in Figure 9. In this process steam (low pressure) is used to heat the area around and between the two wells. Low pressure steam is then injected into the top well where it heats the overlaying bitumen which flows down through the heated area to the lower well where it is drawn off and pumped to surface.

The test site may be used to conduct a member of different recovery processes and negotiations are underway for testing of other recovery concepts.

COLD LAKE DEPOSIT

The Cold Lake Oil Sands Deposit is the 2nd largest of Alberta's four main oil sands deposits and contains some 34 x 10^9 m^3 of bitumen in place. The deposit consists of four main pay zones which from top to bottom are: Upper Grand Rapids, Lower Grand Rapids, Clearwater and the Wabiskaw-McMurray. A summary of the information on these pay zones is given in Tables 2 and 3. A typical cross-section of the Cold Lake Deposit is given in Figure 10.

The Upper Grand Rapids zone consists of continental to marine deposits and contains a high percentage of quartz associated with the high energy depositional environment. The zone is extensive over the area but discontinuous and thin with 5 to 10 meter pays. Isolated pays, however, 30 meters thick can be found in shoe string channel deposits.

The Lower Grand Rapids zone is predominantly a Marine shoreline deposit with associated continental deposits. The deposit is less extensive, more continuous and although pays are thin, (5 to 20 meters) they often contain well sorted sands with good permeability, porosity and bitumen saturation.

The Clearwater zone has been the zone of most commercial interest. Although it is of limited extent, this largely marine shoreline deposit (in the best areas deltaic) often contains thick pays of high permeability and porosity and good bitumen saturation.

The Wabiskaw-McMurray zone represents a mainly continental deposit filling in the lows of the underlaying Devonian unconformity. Except in the far north of the deposit, this zone has the least economic potential as pays are thin and inconsistent and often underlaid by thick water sands.

Esso discovered that if steam was injected into the Clearwater member of the Cold Lake deposit above fracture pressure, that the fracture was retained within the Clearwater member. In addition the fractures were all lined up in a northeast-southwest direction perpendicular to the nearest mountain range. They further observed that as the steam moved out of the fracture, it condensed and cooled giving up its' heat in the zone along the fracture (Figure 11). Leakage of water from the fracture was inversely proportioned to the temperature since the heated bitumen tended to form a bitumen bank which reduced fluid leakoff. This effect tended to concentrate the condensed water in the region further away from the well. When injection was stopped and the well placed on production, the hot bitumen near the well was produced in preference to the water which was mainly further away. Thus good oil production rates were achieved at low water/oil ratios. Typically for pay thicknesses of ~30 meters, 7,000 to 9,000 m^3 of 80% quality steam are injected on each cycle for 7 or 8 cycles giving a CDOR (calendar day oil rate) of 10 to 15 m^3/day SOR of 2 to 4 and ultimate recovery of ~17%.

Esso and others have used this method to exploit production from the Clearwater member of the Cold Lake deposit with current production running at about 12,000 m^3/day.

While technology existed, or was being rapidly developed for obtaining bitumen from the Clearwater member of the Cold Lake deposit, AOSTRA was concerned about; the poor ultimate recovery of above fracture pressure steam stimulation process, the poor results of some of the thinner Clearwater pays and the lack of technology for exploitation of the other three oil sands zones. AOSTRA has sponsored three pilots to address these problems.

In 1977 AOSTRA joined with BP Exploration Canada Limited, Hudson's Bay Oil and Gas and Pan-Canadian Petroleum in a Pilot in a 35 meter (Figure 12) section of the Clearwater member of the Cold lake deposit designed to study the use of air or oxygen following above fracture pressure steam stimulation as a means of improving ultimate recovery. It had been noted that following steam stimulation, off-fracture trend gas communications often existed. it was also noted that the oil easily auto-ignited following heating by steam and that heat could be more economically transmitted to the reservoir by means of an oxidizing gas, particularly by using pure oxygen, rather than by steam injection.

The results of this pilot have been encouraging and have born out the assumptions on which the pilot was based. Off trend communications have been developed throughout the pilot area and although these are believed to be near the top of the pay zone the alternate injection of O_2 and water in a modified drive process has been found to be a cost effective way of producing substantial bitumen beyond that produced by steam-stimulation. Control, as with all combustion projects, has been an area of concern, however, problems have been overcome as they arose resulting in a successful pilot operation.

While the commercial exploitation of the Clearwater formation has been an important economic factor in Alberta, it represents only 25% of the in-place oil in the Cold Lake deposit. The larger Grand Rapids formation contains 67% of the oil in place but has been largely unexploited mainly due to the thinner discontinuous pays broken up by shale breaks and water zones.

In 1983, AOSTRA joined with BP Exploration Company and Petro Canada in a test of above fracture pressure steam stimulation in the Cold Lake area Grand Rapids Formation (Figure 13).

Results of this single well test were encouraging, however, question of recovery mechanism and zone isolation were not completely resolved.

While commercial exploitation is taking place in the better parts of the Clearwater zone, some parts of the deposit are much thinner and much more complex (Figure 14). In these zones the mineralogy of the rock is very complex containing clays, smectites, acid soluble iron and up to 10% detrital carbonate. These deposits therefore are highly susFeptable to fluid-rock interactions, mineral transformation and plugging.

In 1984 AOSTRA joined with Bow Valley Industries & Cold Lake Heavy Oils Ltd. in a pilot designed to investigate the use of additives with the steam and improved operating procedures to: (a) reduce adverse fluid-rock interactions and formation damage; (b) improved reservoir conformance leading to higher recovery (c) improved CDOR's and steam/oil ratios.

The results of this pilot have been encouraging to date and indicate that thinner zones of the Clearwater formation with a more complex geology and minerology can be exploited if care is taken in the recovery process and if additives are used with the steam.

HEAVY OIL

Between the Cold Lake deposit and the Lloydminster area and along the Alberta/Saskatchewan border, in a trend extending from the Lloydminster region in the north to the Suffield block in the south, heavy oil (16^{o} to 24^{o} API gravity; 100 to 400 m•Pa•s viscosity at reservoir conditions) deposits occur.

The most important group of deposits are those included in the Lloydminster-Wainwright area where heavy oil reserves are confined to the Lower Cretaceous Mannville group. In this region, the Mannville Group consists of a sequence of sands and interbedded shales, complexly differentiated, containing a total of nine different formations (Figure 15). The basal Dina Formation is correlative with the McMurray Formation to the north. The sequence from the Cummings Formation through to the Colony Formation correlates with the Upper Mannville in the oil sands area. The fact that the Mannville Group is divided into so many units is a reflection of the degree ho which the more extensive Mannville units to the north are differentiated in the Lloydminster area. Individual heavy oil pools, commonly of very limited lateral extent, occur at virtually all levels within the Mannville section. Many of the pools are characterized by water legs below the pay zones. The best reservoirs are in the Sparky and Waseca Formations, whereas the McLaren, G.P., Rex, and Lloydminster units contain pools of intermediate magnitude and Cummings and Colony sands contain very little oil.

Heavy oil reserves also occur in the Suffield block further to the south. Here the oil is mainly contained in Glauconitic sands of the lower Mannville Group.

The heavy oil deposits are dominated by thin pays (often <5m) and/or by being underlain by water. It is these features which have limited recovery (often 3 to

5% on primary with another 3 to 4% from water flooding). AOSTRA has sponsored two pilots in these areas which have addressed these problems.

In 1978 AOSTRA joined with Pacific Petroleums Ltd. (later PetroCanada) in conducting steam flooding and wet forward combustion tests on a thin (~4m) heavy oil deposit in the Lloydminster-Wainwight area (Viking Kinsella Wainwright D Pool). This pool had seen very limited primary production and no water flooding.

The geology anH petrophysics of the pool are shown in Figure 16 and Table 4. The Kinsella "D" pool, which is typical of many pools in the heavy oil trend, is a thin combined stratigraphic-structural trap. The pool itself is of limited extent being separated from the larger "B" pool and bounded on the east and northern updip edge by shale - in filled channels.

Prior to conducting the pilots, it was assumed that the higher water saturated zones at the base of the deposit would provide a zone of high transmissibility and injectivity. This proved not to be the case. Injection of steam was not at sufficient a rate to transmit heat to the reservoir and the steam pilot was abandoned.

Air injectivity was sufficiently high to sustain combustion, however, the high viscosity of the oil ahead of the front and the high oil saturation limited transmissibility ahead of the combustion front. Under these conditions production rates were not as high as anticipated and air injection was not sufficiently high to promote an economic advance of the combustion front through the reservoir and the project was terminated.

Work on recovery from thin reservoirs is continuing with consideration being given to:

- ☐ *(a) Water flooding the reservoirs first to provide some mobility and injectivity,*
- ☐ *(b) Using O_2 rather than air to reduce the volume of gas injected and required to be transmitted through the reservoir and produced at the production wells.*
- ☐ *(c) The use of CO_2 in a non-thermal immiscible displacement process to precondition the reservoir and lower the viscosity ahead of a displacement process using water or polymer.*

AOSTRA, together with Alberta Energy Company, Dome Petroleum and Westcoast Petroleum in 1979 conducted a pilot test of forward combustion in the Suffield Heavy Oil area.

The reservoir unit at this pilot is within the Glauconitic Sandstone Formation, of the Lower Cretaceous upper Mannville Group. Within the pilot area, the reservoir thickness averages 45 m, of which approximately the upper 20 m is oil saturated. The depositional environment is interpreted as north-south trending progradational beach system, which was seaward to the coast. An abnormally large sand thickness was apparently controlled by localized basement faulting which occurred during deposition. The formation is consolidated, and fairly homogeneous at the base, with a coarsening-upwards sequence followed by a fining upwards to the point of capping the reservoir sands with lagoonal shales. The reservoir is underlain by shales and calcareous sediments of the Ostracode zone.

Petrophysical properties of the reservoir are given in Table 5 and the viscosity temperature relationship of the crude is given in Figure 17. The dominant feature of the reservoir is the viscosity of the crude and the large underlaying water leg and very strong bottom water drive. Recovery then is as much a problem of prevention of water coning as to providing drive energy for enhanced recovery.

The problem of water coning is the second most pressing problem preventing good recoveries from many pools in the heavy oil belt. Current research is centering on:

- ☐ *(a) the use of horizontal wells or laterals*
- ☐ *(b) the use of additives*
- ☐ *(c) improved well completions*

CONCLUDING REMARKS

This paper has stressed the diversity of reservoir conditions found in Alberta's bituminous and heavy oil deposits and the necessity of developing a recovery process which matches the reservoir conditions found at any particular site. Inherent in this process is the necessity of conducting properly planned, instrumented and executed pilot operations prior to proceeding with commercial development. In the paper 10 AOSTRA sponsored pilots have been discussed. Of these two have lead to commercial operations. Of the remaining eight, while a great deal was learned, it was realized that a new approach was required if operations were to be successful. Even in the case of the two pilots which lead to commercial development, a great deal was learned in these piloting operations which contributed to the successful commercial operation.

The main factors influencing a successful pilot were:

- ☐ *(a) A careful evaluation of the geology, minerology and petrophysics, not only of the reservoir, but of the pilot site, prior to commencement of piloting operations.*
- ☐ *(b) The choice of a recovery process which was consistant with the geology, minerology and petrophysical properties present at the pilot site.*

While a number of other factors such as engineering, planning, execution and management were important they were minor compared to the over laying factor of choice of a recovery process consistent with the reservoir present. Here in China there is also a variety of reservoirs. While steam stimulation below fracture pressure will undoubtably be a successful recovery process in many reservoirs it will not be universal.

ACKNOWLEDGMENTS

The author wishes to acknowledge the contribution of the Geological Survey of Alberta for much of the geological information contained in this paper and the Energy Resources Conservation Board, Province of Alberta, for the reserve estimates.

Table 1
ERCB 1985 Estimate of Alberta Oil Sands, Heavy Oil, and Bituminous Carbonate Reserves (Billions of m^3)

Oil Sands		
Wabiskaw-McMurray	151	
Cold Lake	35	275
Peace Piver	12	
Carbonates	68	125
Total	**266**	**400**

Heavy crude oil 1.18
[density >0.9 kg/m^3 (25^{o} API)]

Table 2
Bitumen Reserves and Basic Data, Cold Lake Area

Deposit depth to top	**Area extent**	**Net Pay**	**API gravity**	**Bitumen Content**	**Porosity**	**Bitumen in place (10^6 m^3)**
Upper Grand Rapids 275-500	816	5-20	11-14	0.03-0.12	0.28-0.33	7,400
Lower Grand Rapids 323-525	787	5-20	9-12	0.03-0.14	0.28-0.35	12,202
Clearwater 375-500	561	10-60	10-11	0.03-0.16	0.28-0.36	10,620
Wabiskaw-McMurray 425-600	666	5-10	10-12	0.03-0.14	0.28-0.35	3,955
TOTALS	**2,830**					**34,177**

a - Bitumen mass > 3%

Table 3
Geological parameters Cold Lake area

DEPOSIT	SAND TYPE	DOMINANT CLAY MINERALS	TRAPPING MECHANISMS	DEPOSITIONAL ENVIRONMENTS
UPPER GRAND RAPIDS	Felspathic Litharenite Litharenite Sublitharenite	Kaolinite Illite Smectite	Structural Stratigraphic	Continental Marine shoreline
LOWER GRAND RAPIDS	Felspathic Litharenite Litharenite Sublitharenite	Kaolinite Illite Smectite	Structural Stratigraphic	Marine shoreline Continental
CLEARWATER	Felspathic Litharenite Litharenite Sublitharenite	Kaolinite Illite Smectite	Structural Stratigraphic	Marine shoreline Continental
Wabiskaw-McMurray	Quartzarenite Sublitharenite	Kaolinite Illite	Structural Stratigraphic	Marine shoreline Continental

Table 4
Reservoir Parameters of Viking Kinsella Wainwright D Pool

Well spacing pilot area	2 ha
Average depth to top of Sparky sand	680
Average gross pay thickness	5.5 m
Average net oil pay	4.7 m
Average reservoir temperature	27.8°C
Average porosity	29.9%
Average permeability	360 md
Average oil saturation above o/w contract	70%
Average oil saturation below o/w contract	25%
Oil formation factor	1.04 m^3/m^3
Pool total original oil-in-place	1,590,000 m^3
Original reservoir pressure	5,100 kPa
Oil density	965 kg/m^3
Oil viscosity at original reservoir conditions	400 m•Pa•s

Table 5
Reservoir and Fluid Properties at Suffield Heavy Oil Pilot

Porosity (%)	27
Horizontal permeability (md)	500
Vertical permeability (md)	200
Oil saturation (%)	75
Depth (m)	915
Reservoir pressure (kPa)	10,500
Oil gravity/density (°API/kg/m^3)	14 (973)
Reservoir viscosity (m•Pa•s)	170

Figure 1

General Distribution of the Main Non-Conventional Oil Deposits of Alberta. The Triangular Area Outlines the 70,000 km² Paleozoic "Carbonate Trend"

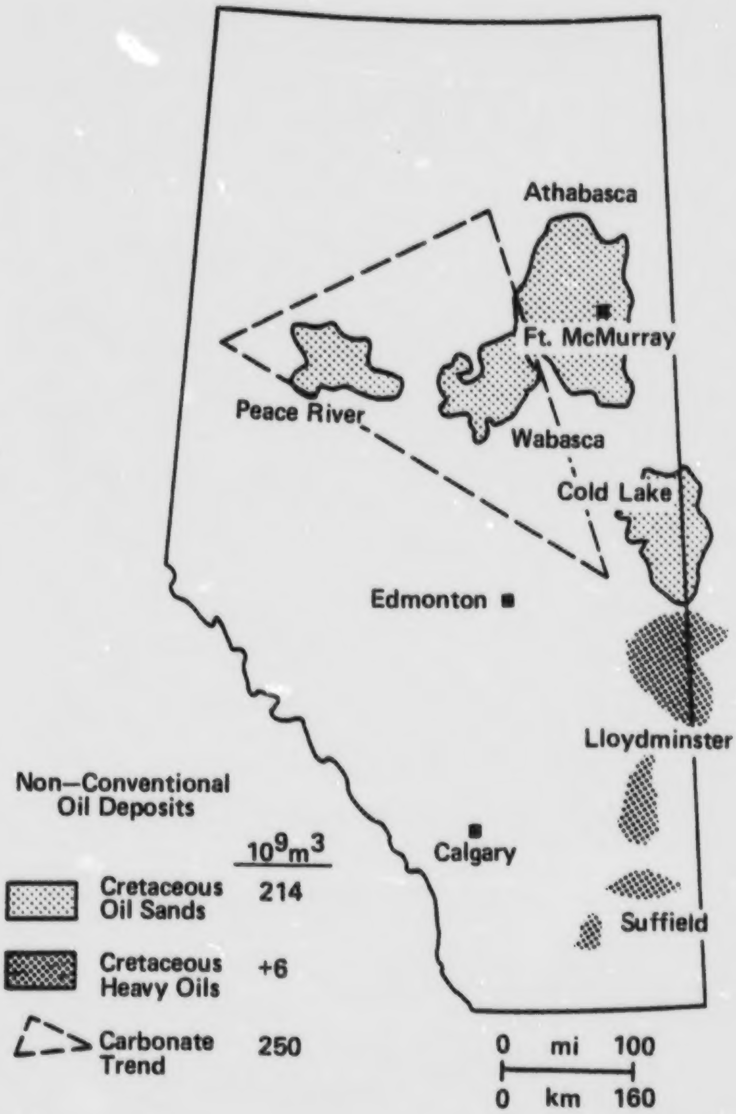

Athabasca
Ft. McMurray
Peace River
Wabasca
Cold Lake
Edmonton
Lloydminster
Calgary
Suffield
Non–Conventional Oil Deposits
10⁹m³
Cretaceous Oil Sands 214
Cretaceous Heavy Oils +6
Carbonate Trend 250
0 mi 100
0 km 160

Figure 2

Typical Peace River Reservoir Parameters

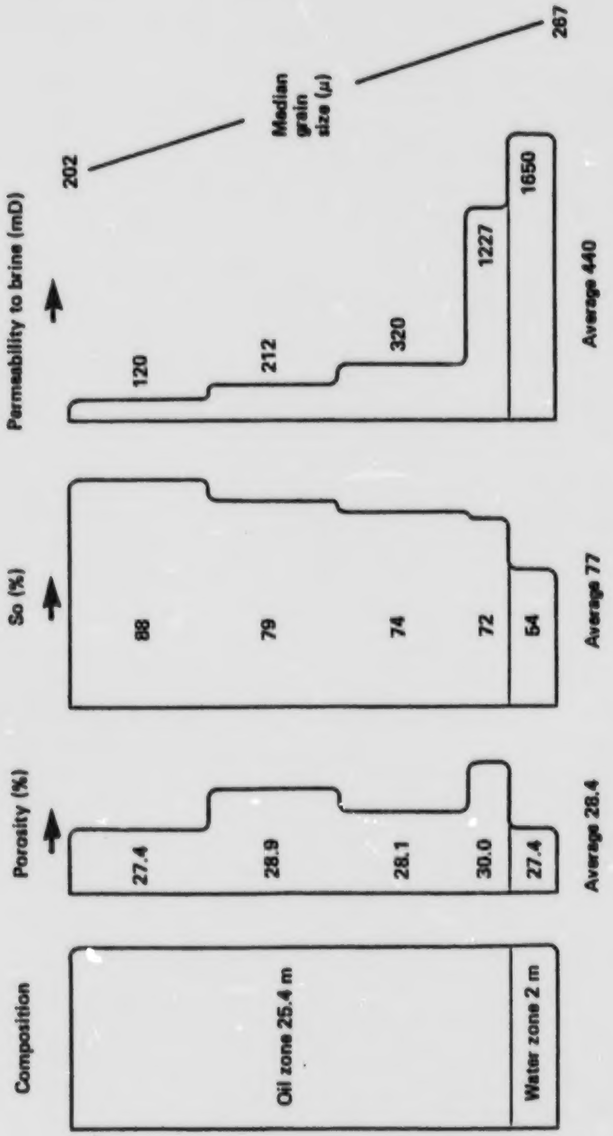


Figure 3
The Carbonate Triangle of Alberta

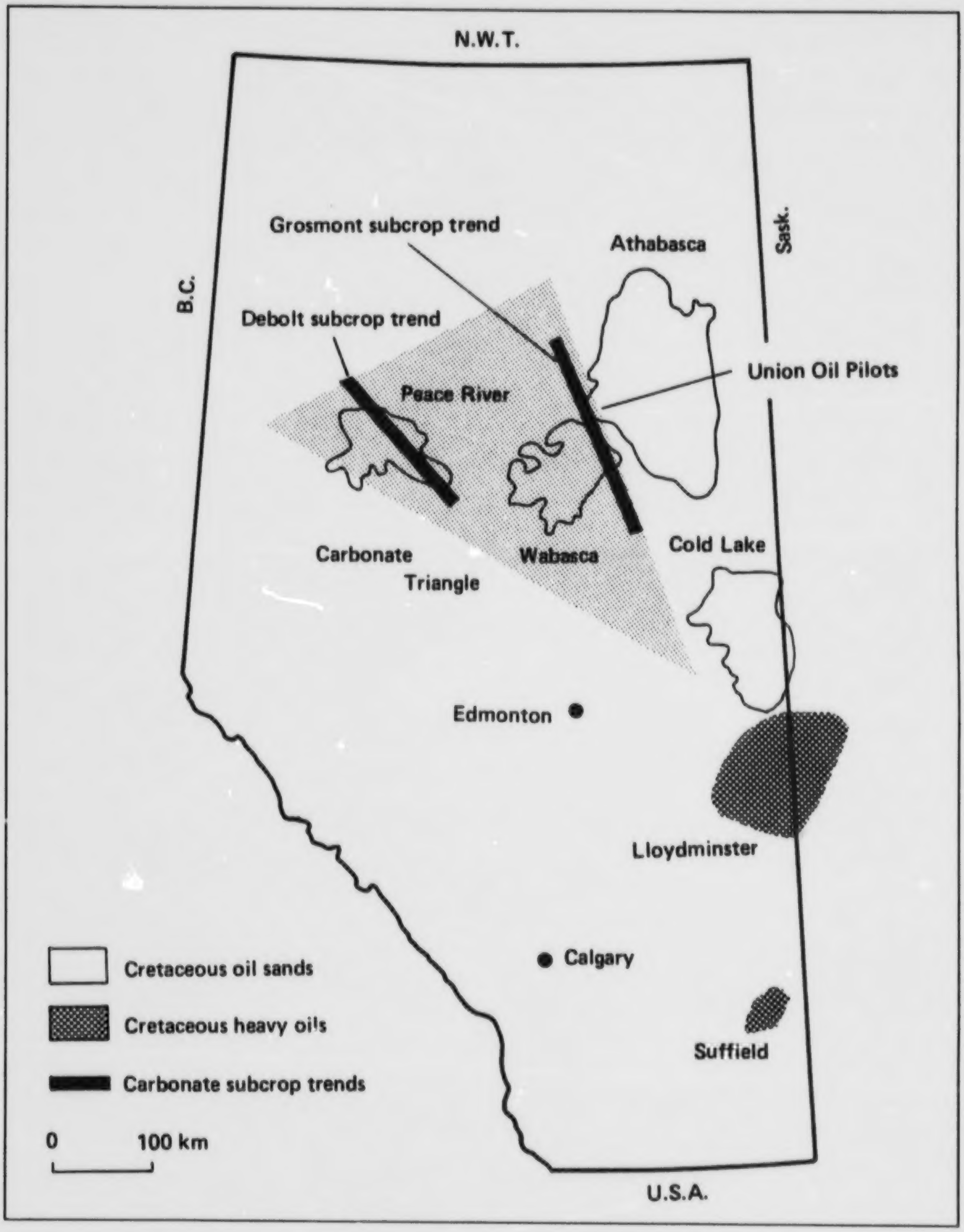

N.W.T.
B.C.
Sask.
Grosmont subcrop trend
Athabasca
Debolt subcrop trend
Union Oil Pilots
Peace River
Carbonate
Triangle
Wabasca
Cold Lake
Edmonton
Lloydminster
Calgary
Suffield
Cretaceous oil sands
Cretaceous heavy oils
Carbonate subcrop trends
0
100 km
U.S.A.

Figure 4

Grosmont Subcrop and Overlying Mesozoic Oil Sands

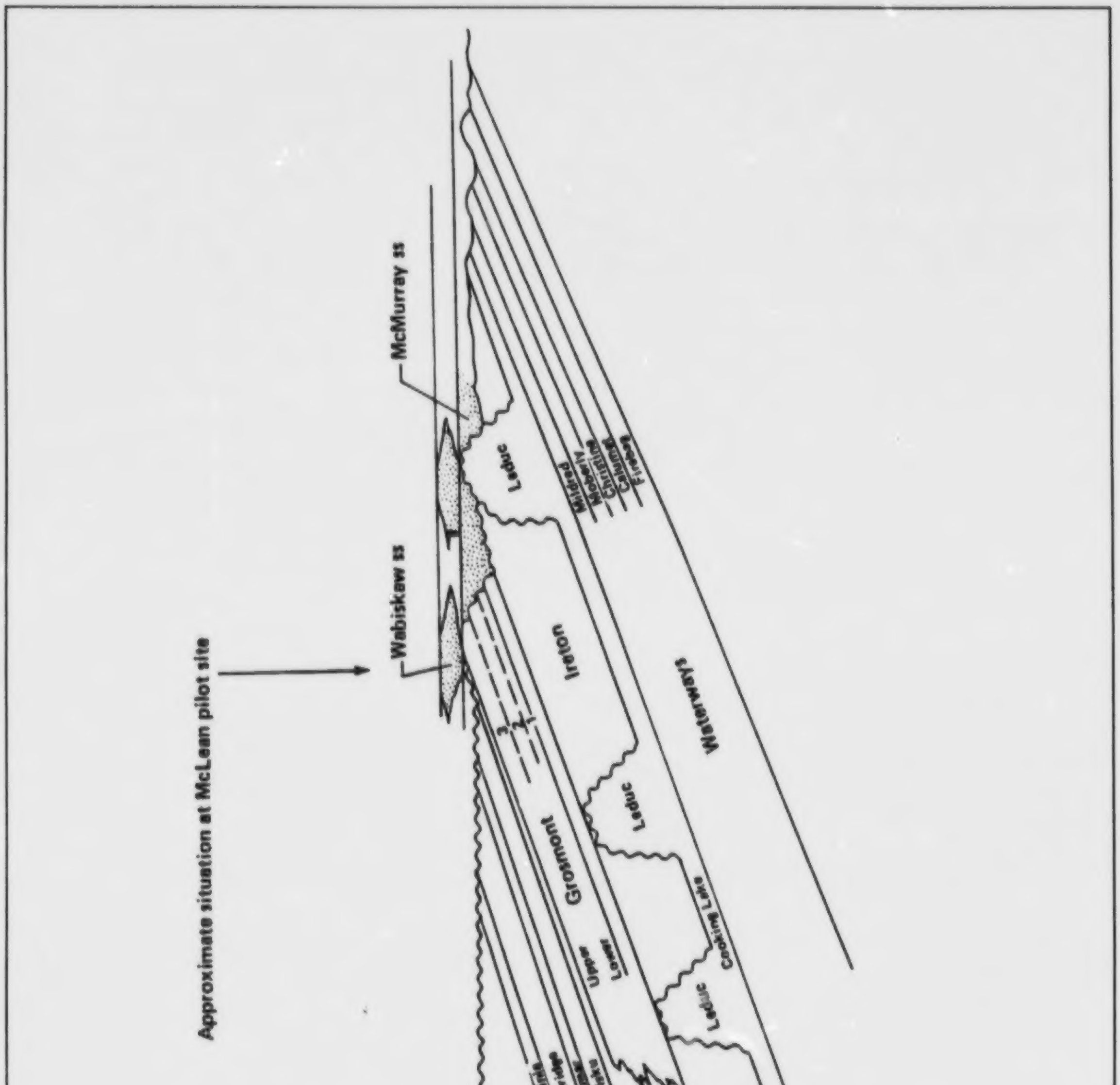

Approximate situation at McLean pilot site
Wabiskaw ss
McMurray ss
Grand Rapids
Clearwater
McMurray
Mannville
Lower Cretaceous
Mesozoic
Winterburn
Graminia
Blueridge
Calmar
Nisku
Grosmont
Upper
Lower
3
2
1
Ireton
Leduc
Leduc
Leduc
Leduc
Leduc
Cooking Lake
Waterways
Mildred
Moberly
Christina
Calumet
Firebag
Beaverhill Lake
Woodbend
Upper Devonian
Paleozoic

Figure 5

Typical Bitumen in Place and Horizontal Permeability for the Upper Grosmont 2 Subunits

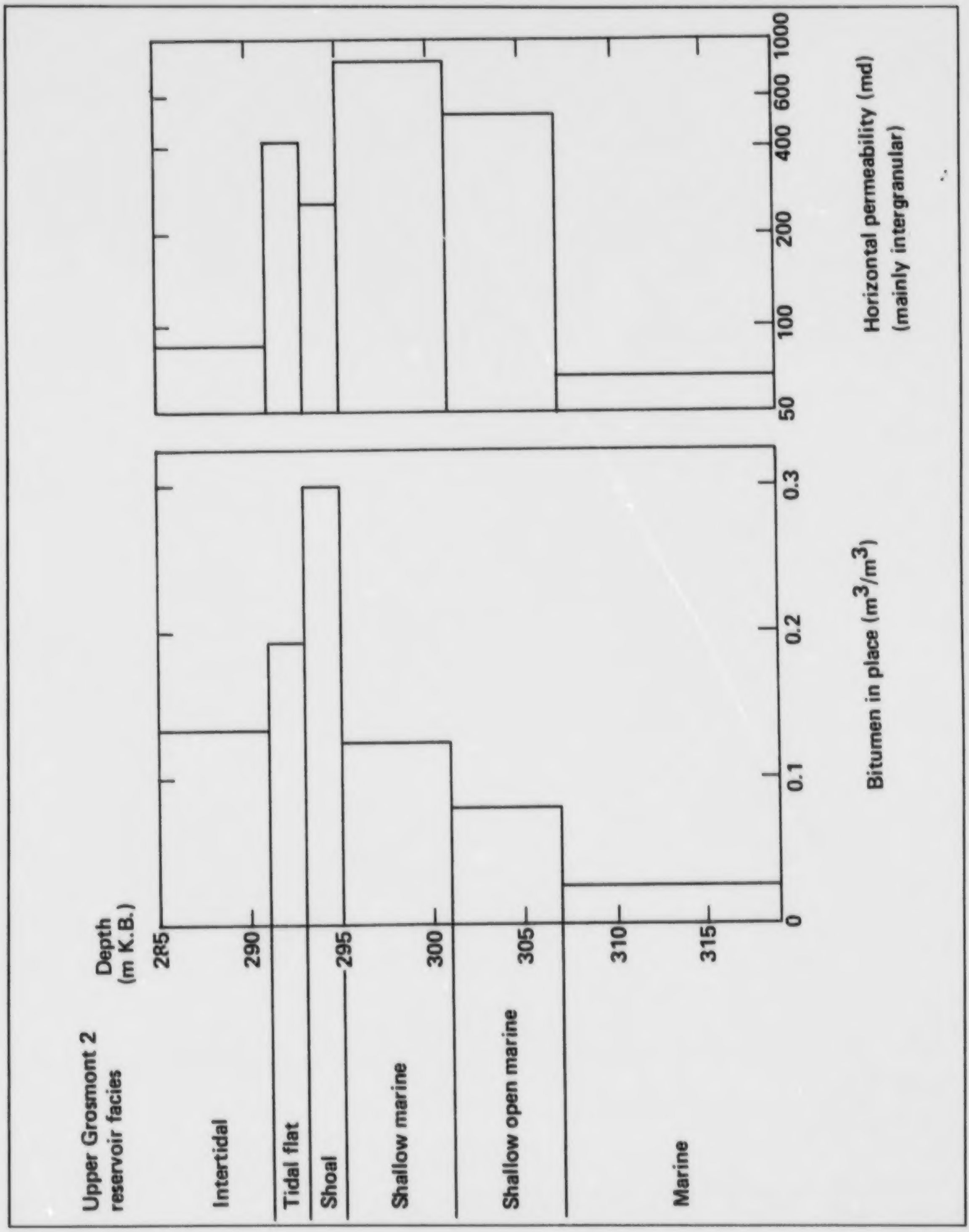


Figure 6

Kearl Lake Project

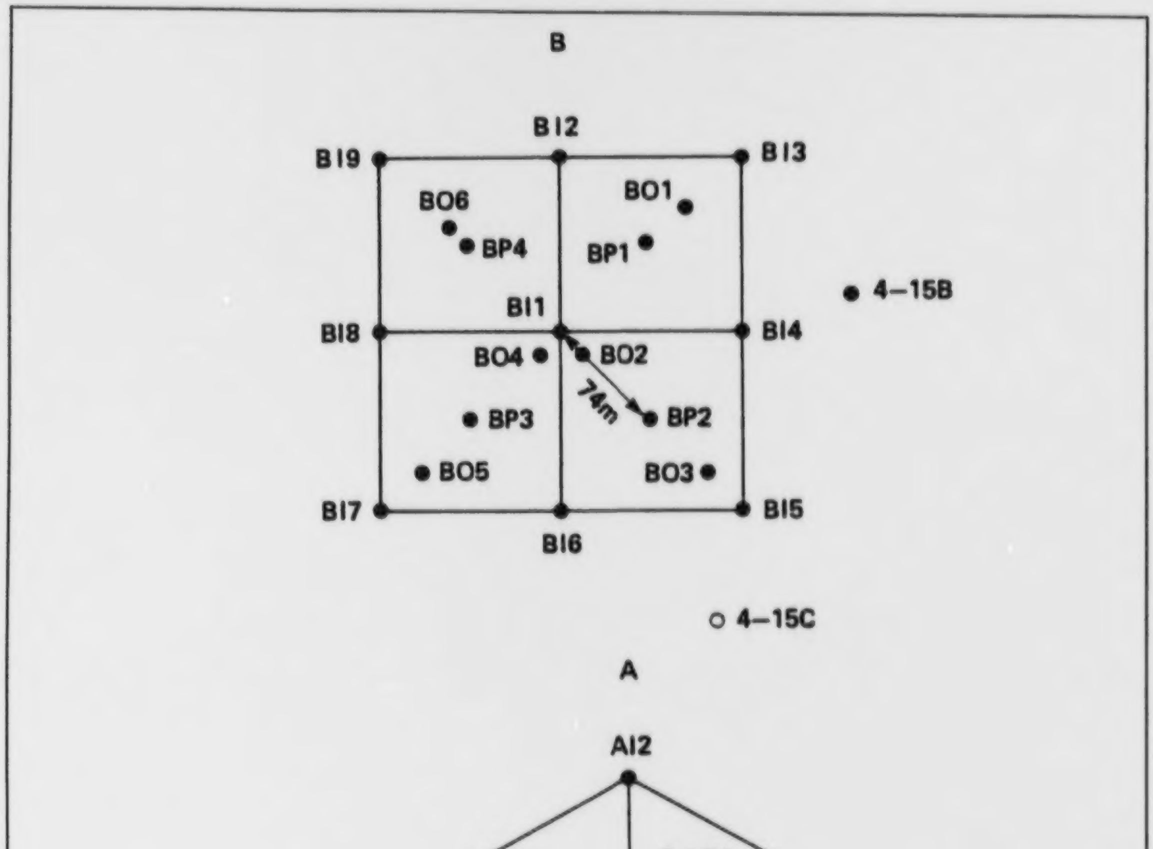

B
BI2
BI9
BI3
BO6
BO1
BP4
BP1
4–15B
BI1
BI8
BI4
BO4
BO2
74m
BP3
BP2
BO5
BO3
BI7
BI6
BI5
4–15C
A
AI2
AO1
AP6
AI7
AP1
AI3
AO3
AO9
AO8
AO2
91m
AP5
AP2
13–10
AI1
AO6
AP3
AO4
AI6
AO7
AI4
AP4
AO5
AI5
0
100
200 m

Figure 7

Bitumen Content in McMurray Formation at UTF Site

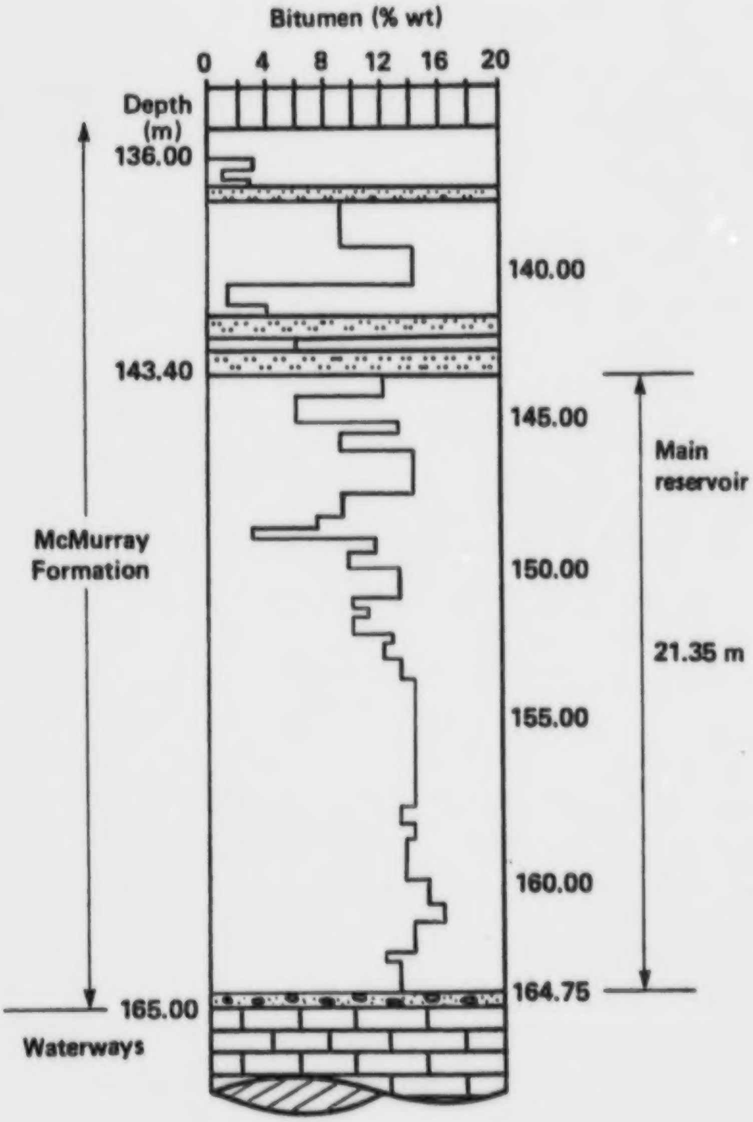


Figure 8

Horizontal Wells for Recovery by Modified Gravity Drainage

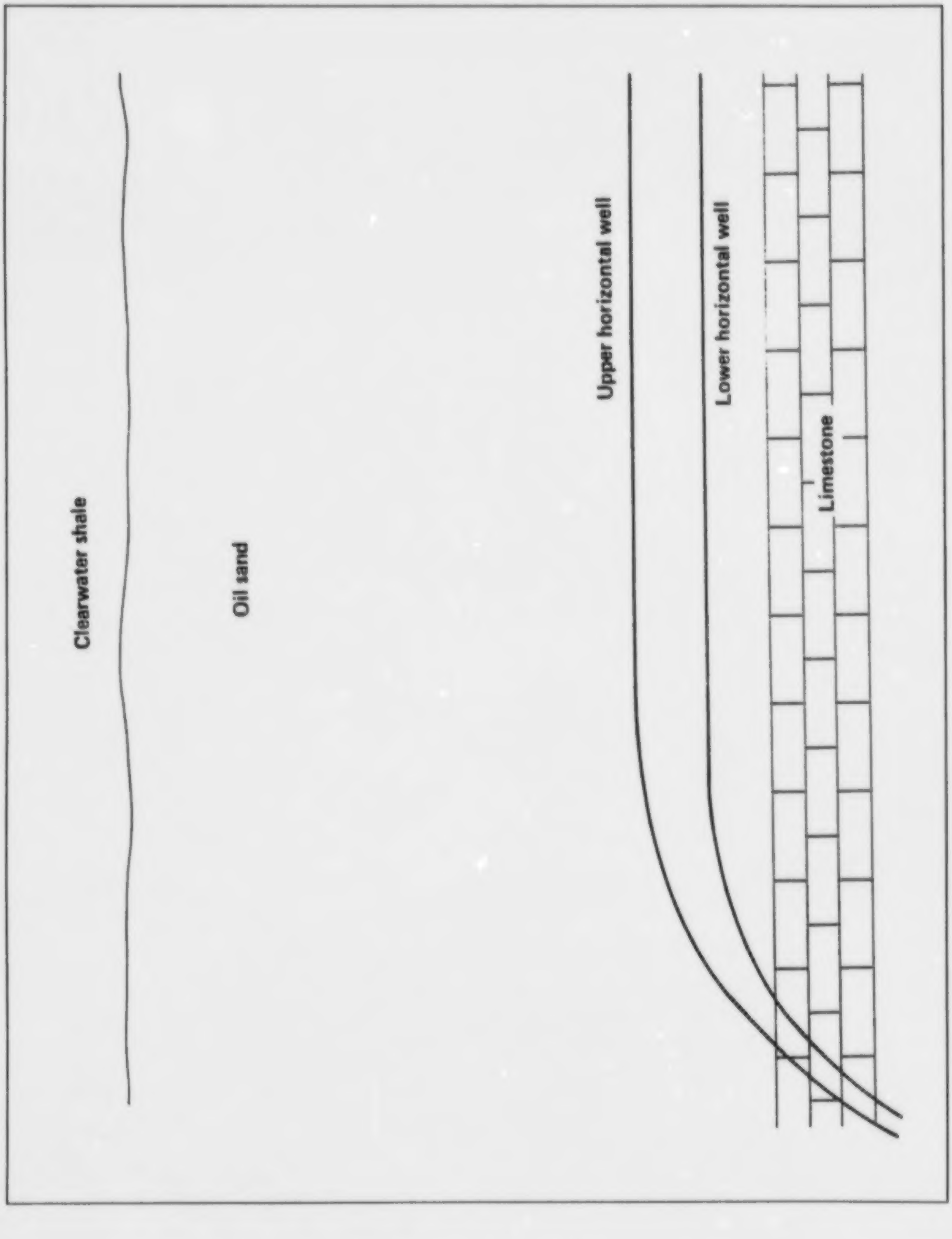

Clearwater shale
Oil sand
Upper horizontal well
Lower horizontal well
Limestone

Figure 9

Growth of Steam Chambers During Recovery by Modified Gravity Drainage

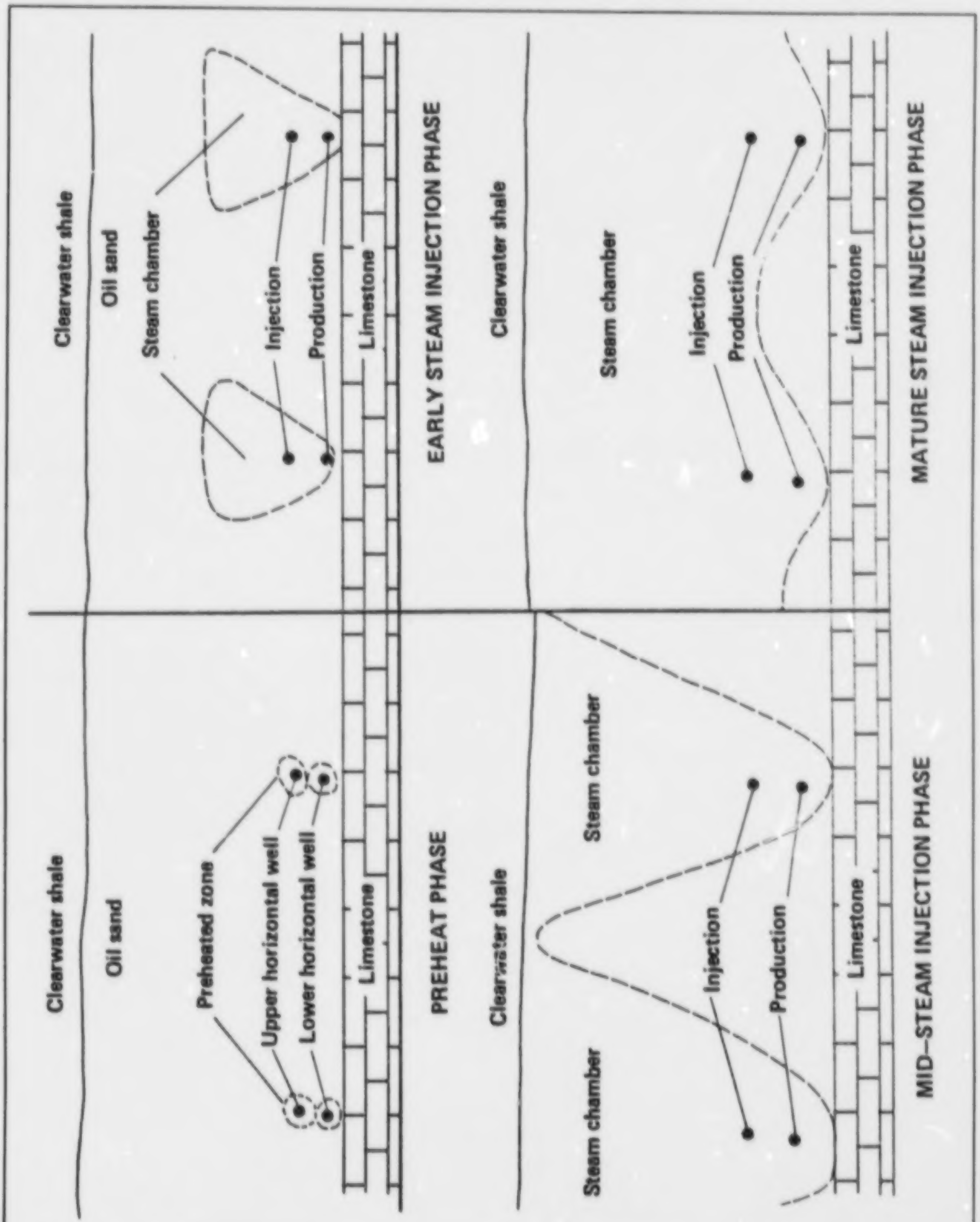

Clearwater shale
Oil sand
Preheated zone
Upper horizontal well
Lower horizontal well
Limestone
PREHEAT PHASE
Clearwater shale
Oil sand
Steam chamber
Injection
Production
Limestone
EARLY STEAM INJECTION PHASE
Clearwater shale
Steam chamber
Steam chamber
Injection
Production
Limestone
MID–STEAM INJECTION PHASE
Clearwater shale
Steam chamber
Injection
Production
Limestone
MATURE STEAM INJECTION PHASE

Figure 10

Cold Lake Sands Structural Cross-section, Showing Generalized Lithologies and Reservoir Configurations

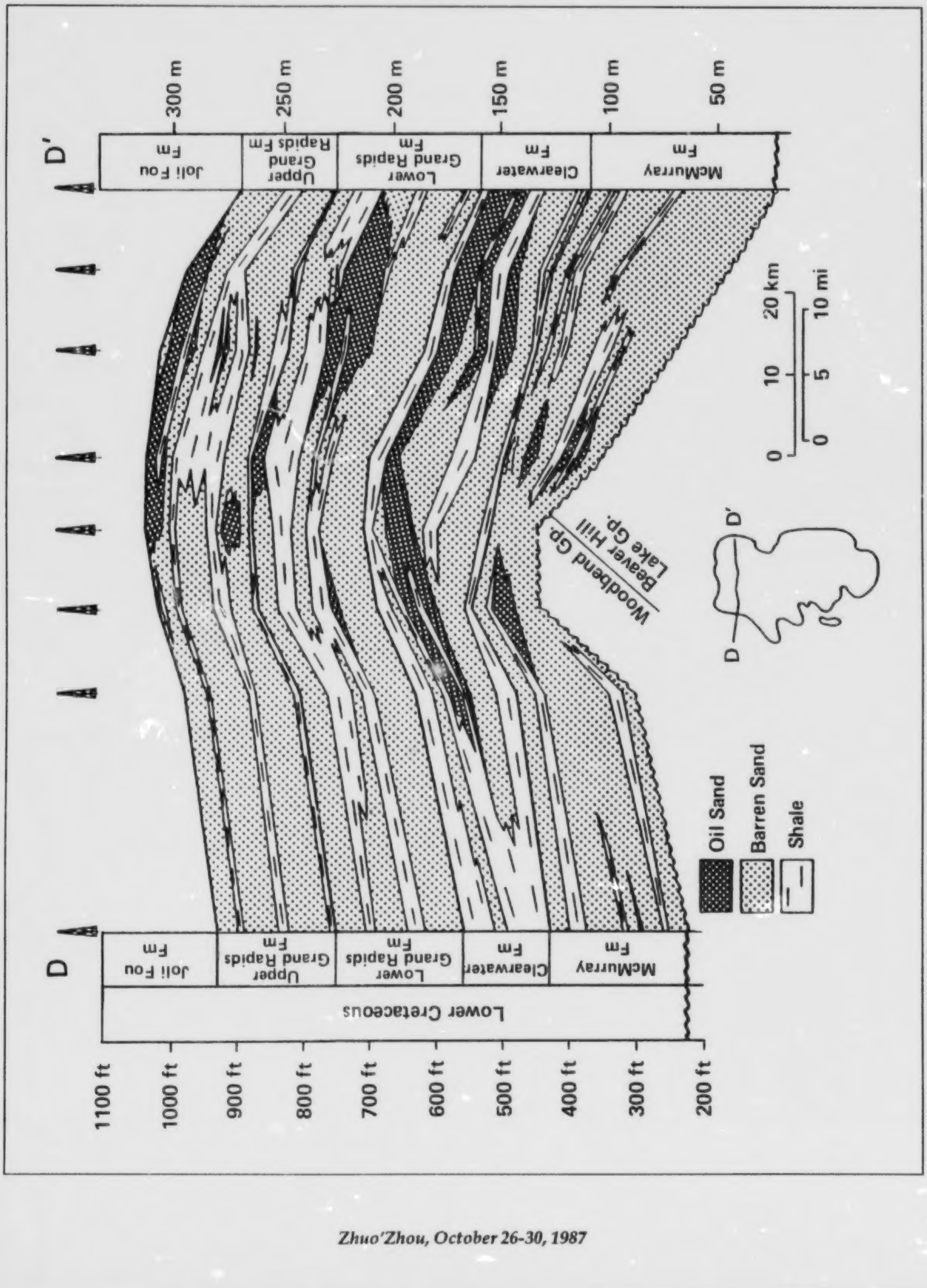

D
D′
1100 ft
1000 ft
900 ft
800 ft
700 ft
600 ft
500 ft
400 ft
300 ft
200 ft
300 m
250 m
200 m
150 m
100 m
50 m
Lower Cretaceous
Joli Fou Fm
Upper Grand Rapids Fm
Lower Grand Rapids Fm
Clearwater Fm
McMurray Fm
Woodbend Gp.
Beaver Hill Lake Gp.
Oil Sand
Barren Sand
Shale
0
10
20 km
0
5
10 mi

Figure 11 (a)

Steam-Stimulation Production at Cold Lake Above Fracture Pressure

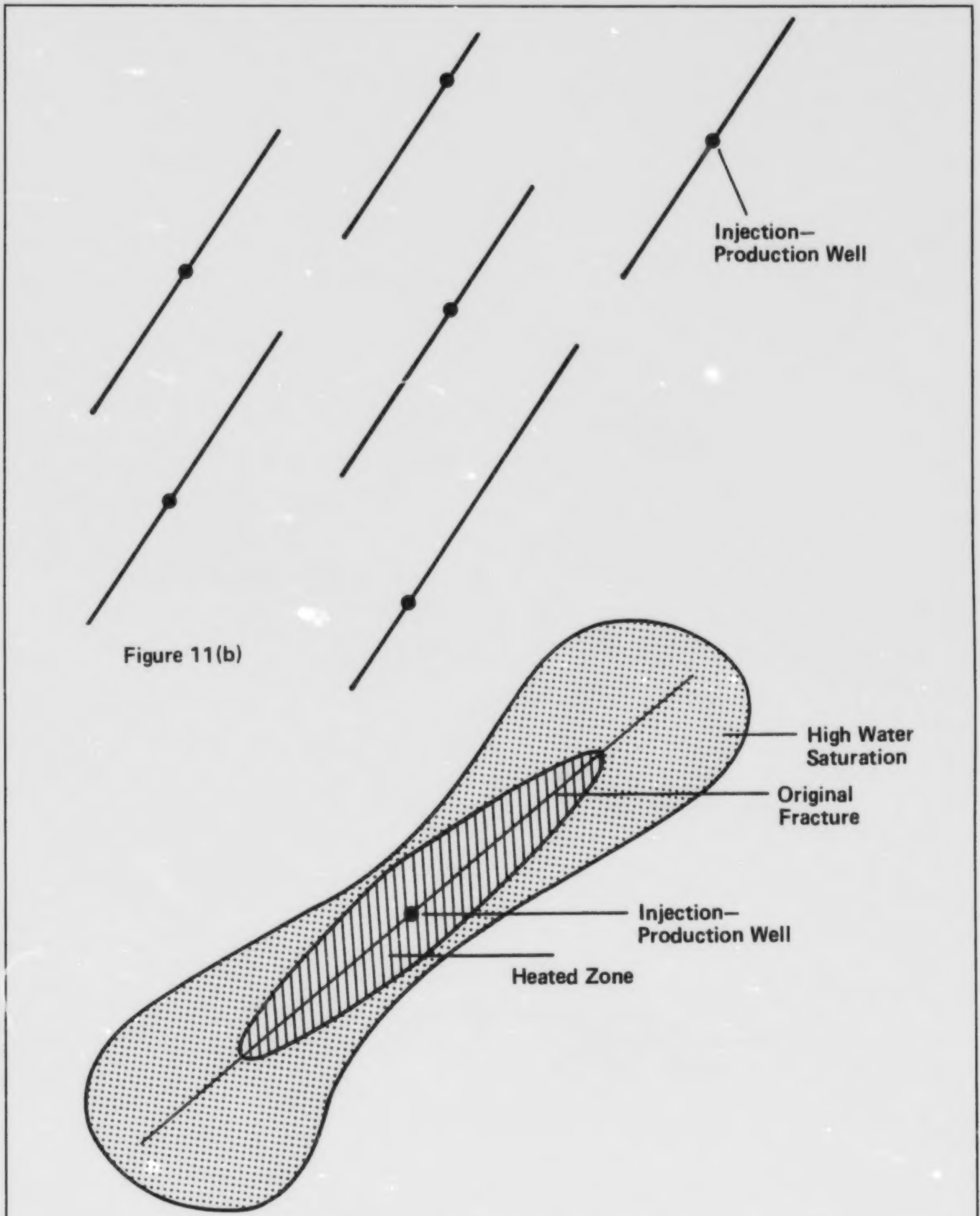

Injection–
Production Well
Figure 11(b)
High Water
Saturation
Original
Fracture
Injection–
Production Well
Heated Zone

Figure 12

Phase A Reservoir Schematic

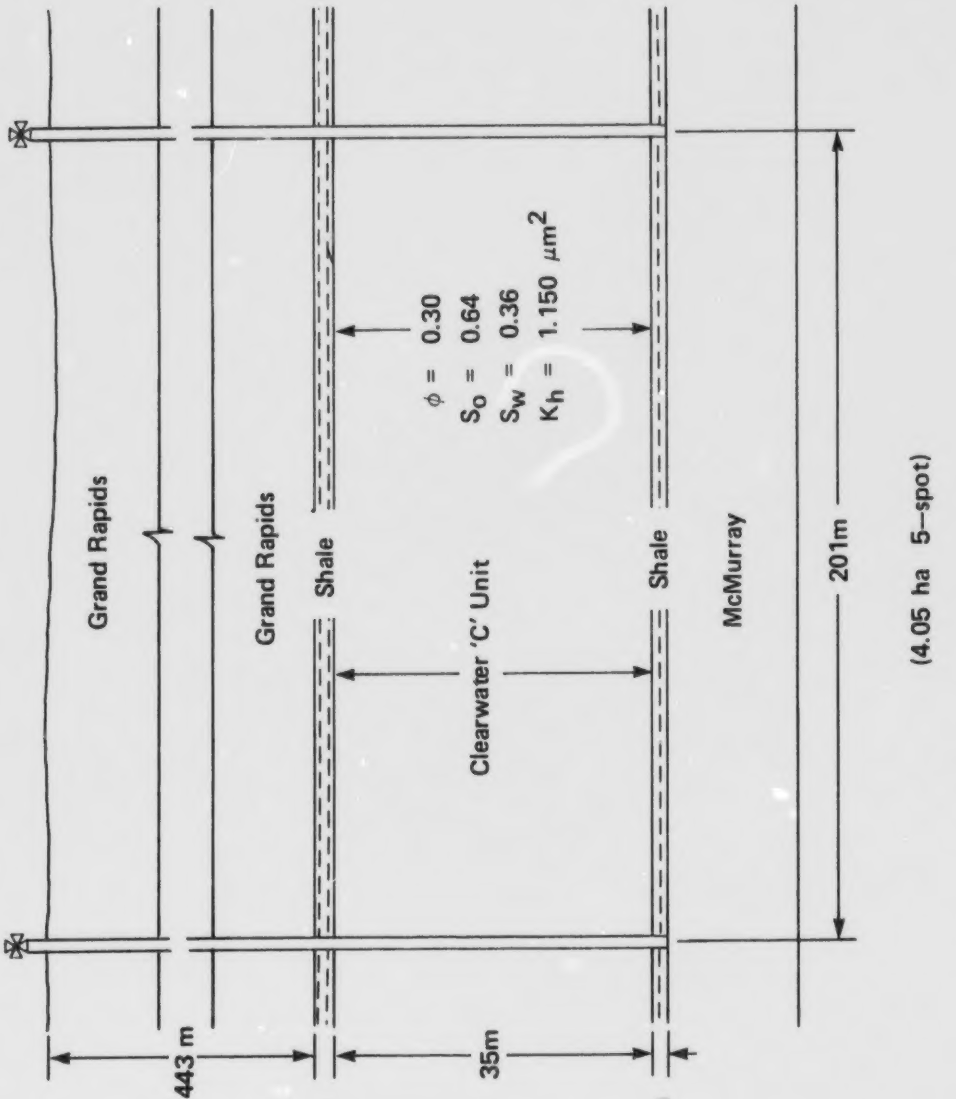

Grand Rapids
Grand Rapids
Shale
Clearwater 'C' Unit
Shale
McMurray
ϕ = 0.30
S_o = 0.64
S_w = 0.36
K_h = 1.150 μm^2
201m
(4.05 ha 5–spot)
443 m
5m
35m
4m

Figure 13

B Unit Reservoir Schematic

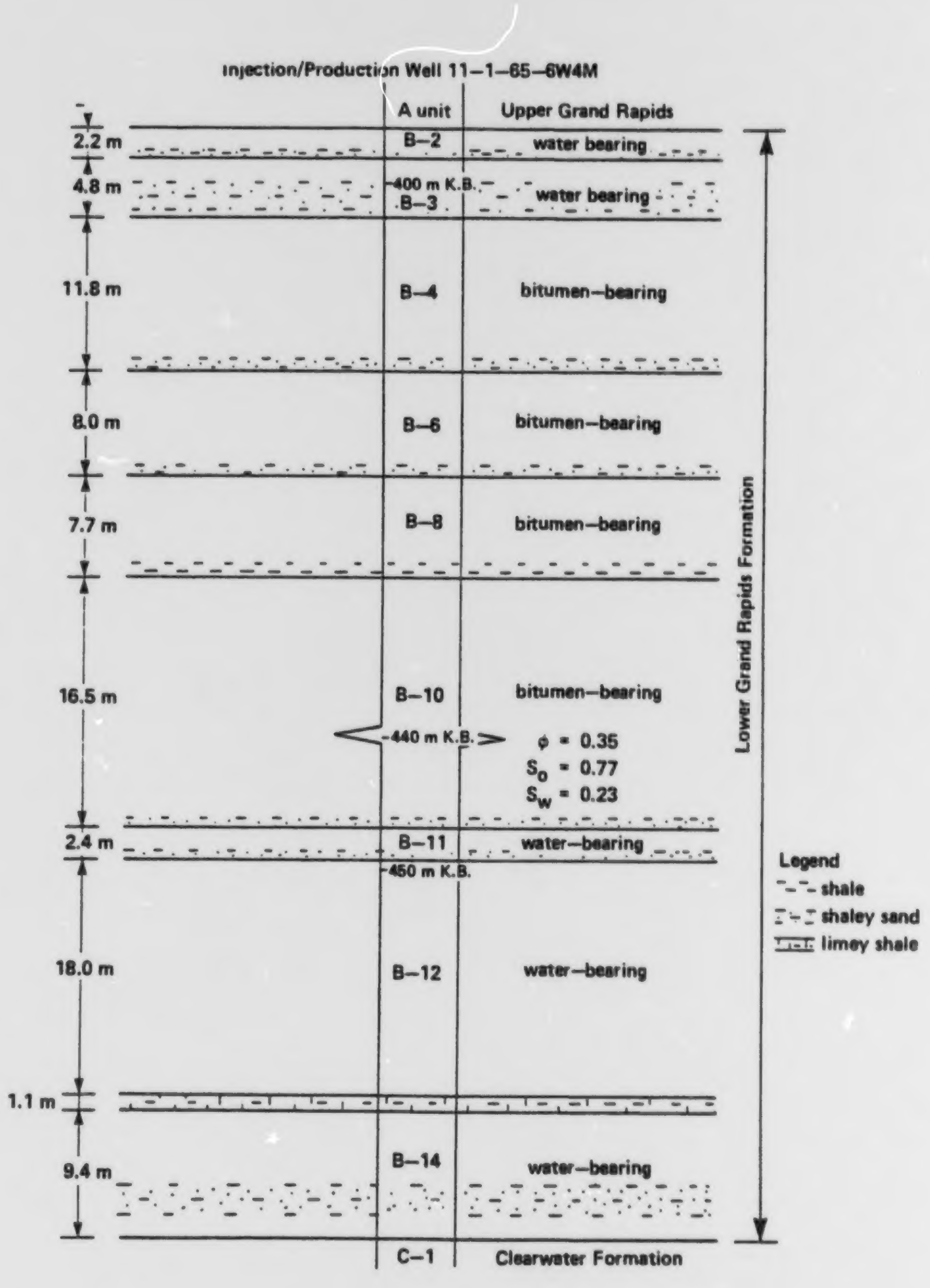

Injection/Production Well 11–1–65–6W4M
A unit
Upper Grand Rapids
2.2 m
B–2
water bearing
4.8 m
400 m K.B.
B–3
water bearing
11.8 m
B–4
bitumen–bearing
8.0 m
B–6
bitumen–bearing
7.7 m
B–8
bitumen–bearing
16.5 m
B–10
bitumen–bearing
440 m K.B.
φ = 0.35
S_o = 0.77
S_w = 0.23
2.4 m
B–11
water–bearing
450 m K.B.
18.0 m
B–12
water–bearing
1.1 m
9.4 m
B–14
water–bearing
C–1
Clearwater Formation
Lower Grand Rapids Formation
Legend
shale
shaley sand
limey shale

Figure 14

Lithology of the Clearwater Formation at the ABC site

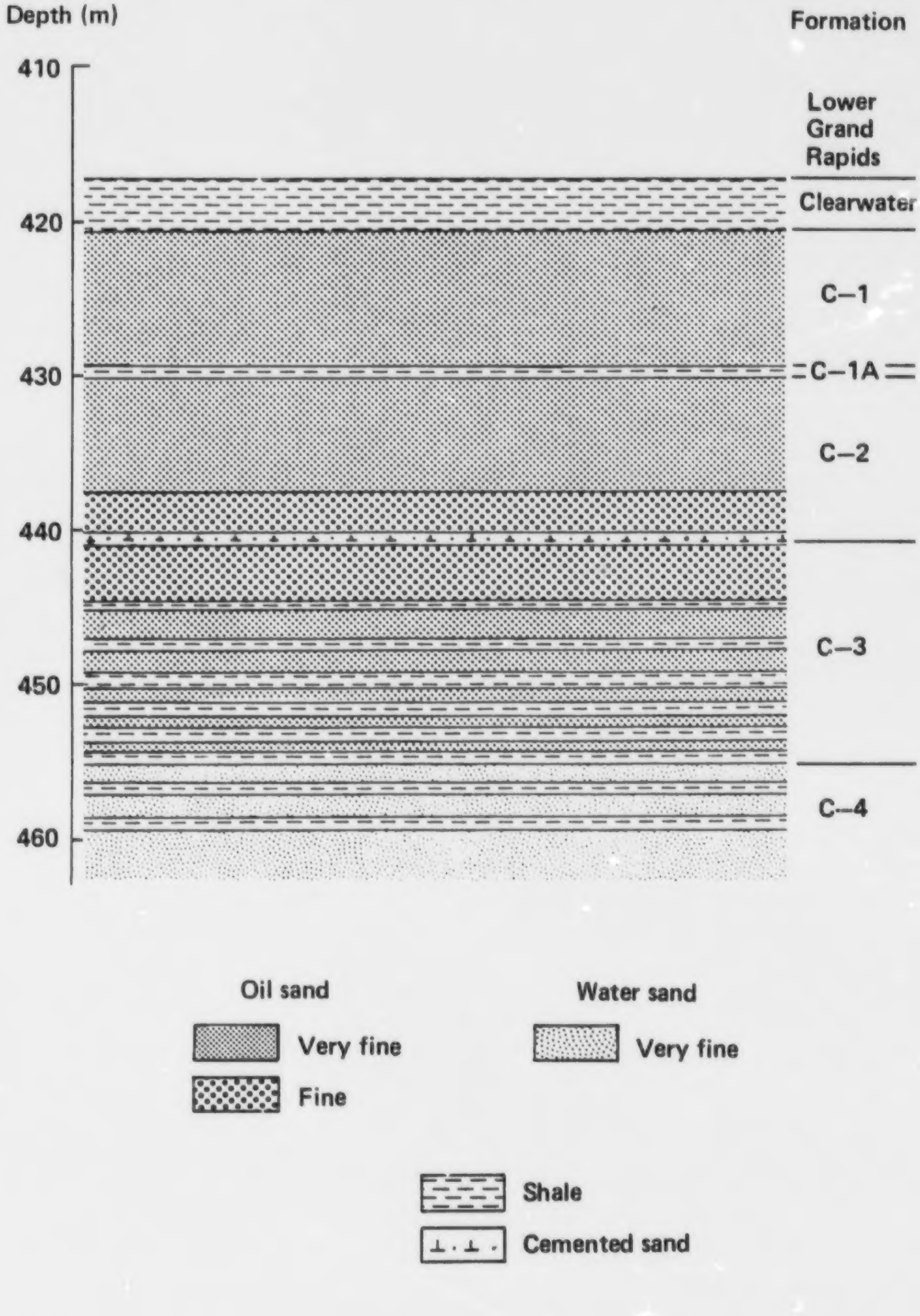

Depth (m)
Formation
410
420
430
440
450
460
Lower Grand Rapids
Clearwater
C–1
C–1A
C–2
C–3
C–4
Oil sand
Very fine
Fine
Water sand
Very fine
Shale
Cemented sand

Figure 15

Schematic Log Section of the Heavy-Oil Bearing Manville Group Strata in the Lloydminster Area

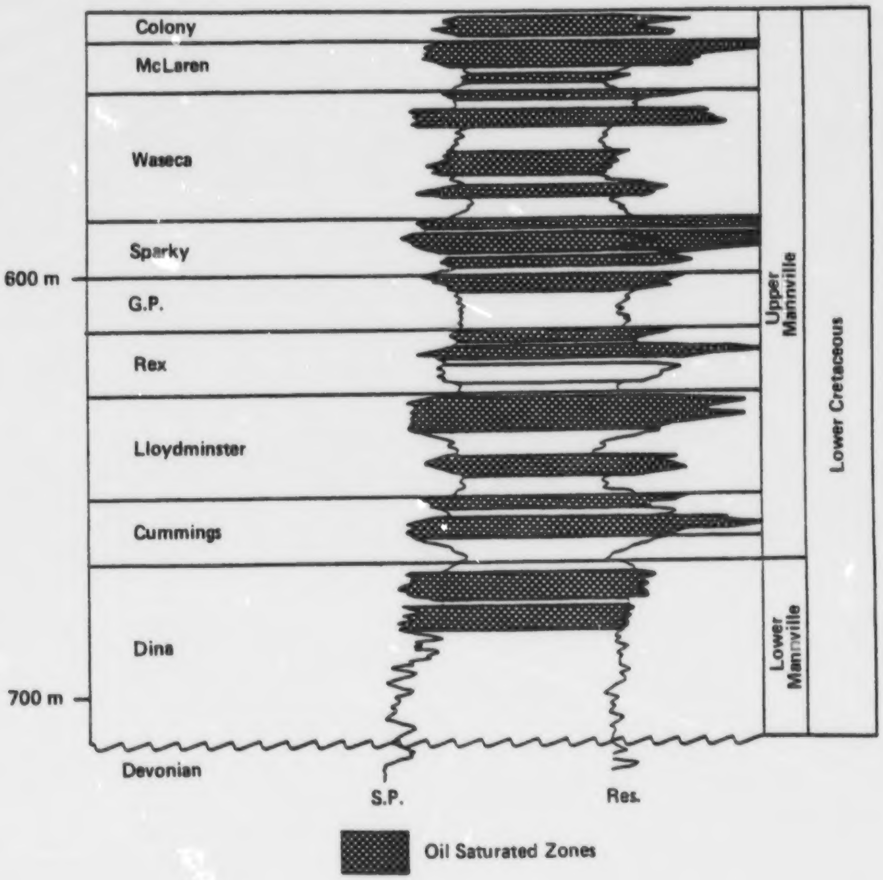

Colony
McLaren
Waseca
Sparky
600 m
G.P.
Rex
Lloydminster
Cummings
Dina
700 m
Devonian
S.P.
Res.
Upper Mannville
Lower Mannville
Lower Cretaceous
Oil Saturated Zones

Figure 16

Reservoir Schematic for the Producing Interval in the Kinsella D Pool

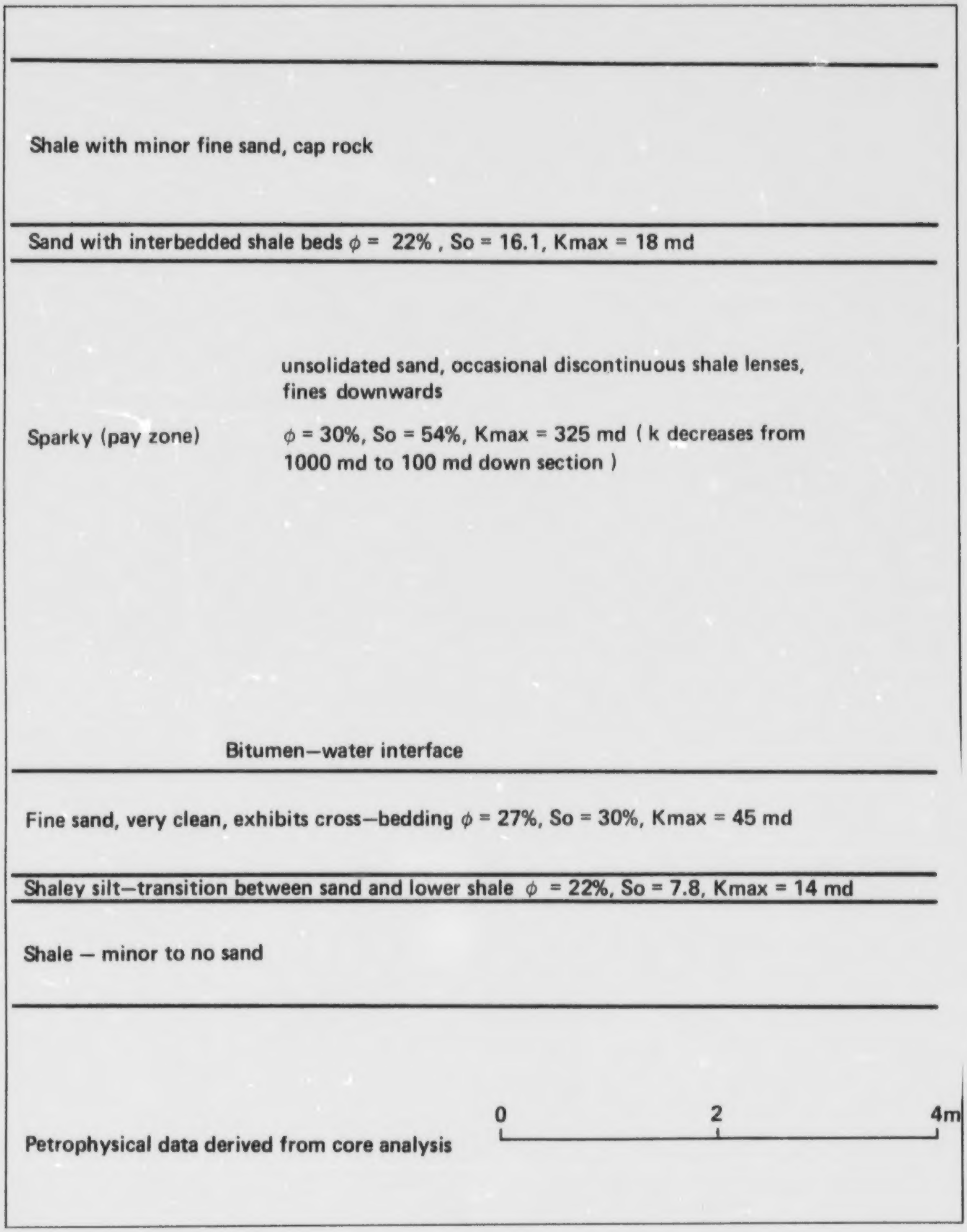
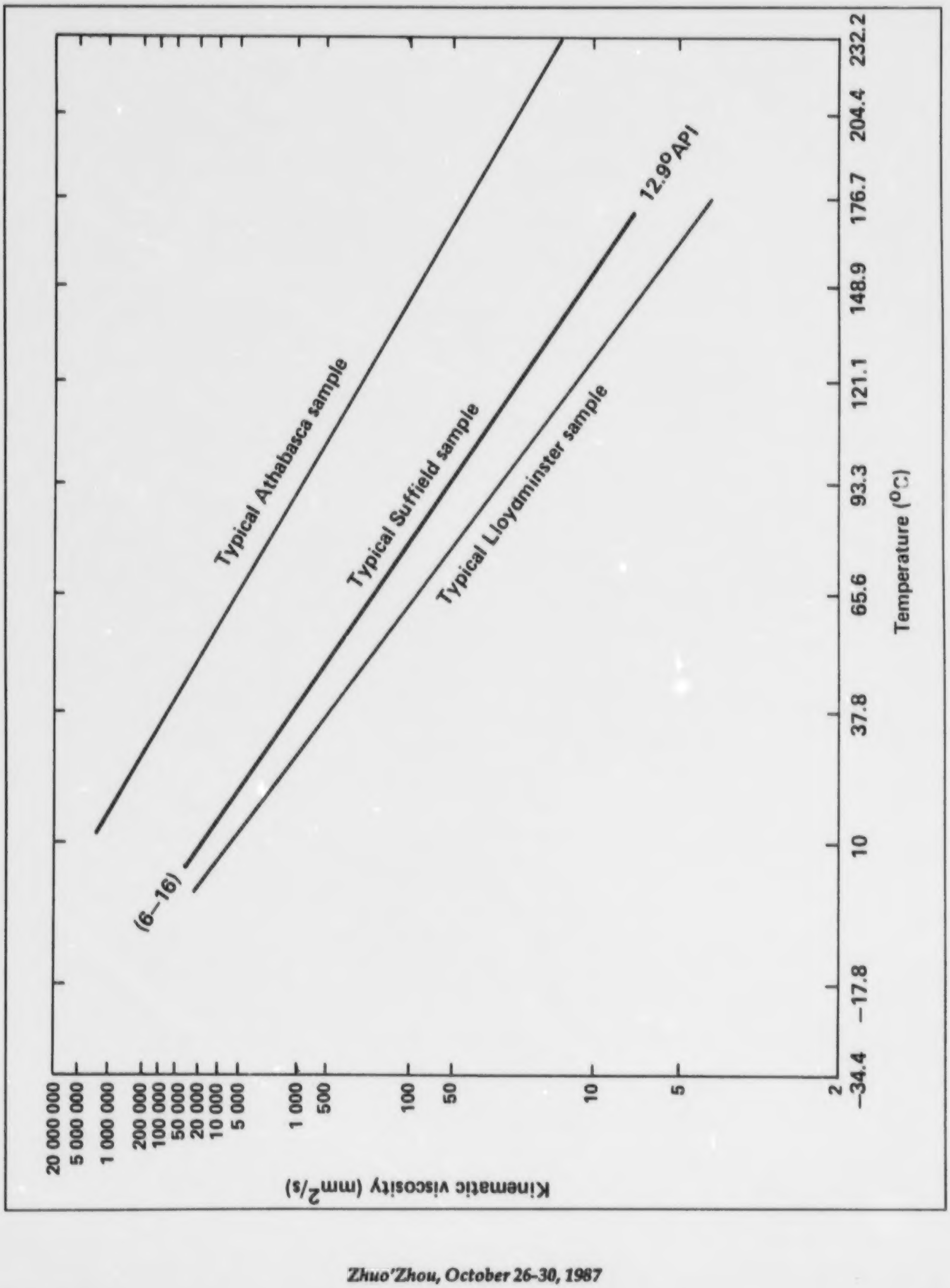

Shale with minor fine sand, cap rock
Sand with interbedded shale beds ϕ = 22% , So = 16.1, Kmax = 18 md
unsolidated sand, occasional discontinuous shale lenses, fines downwards
Sparky (pay zone)
ϕ = 30%, So = 54%, Kmax = 325 md (k decreases from 1000 md to 100 md down section)
Bitumen—water interface
Fine sand, very clean, exhibits cross—bedding ϕ = 27%, So = 30%, Kmax = 45 md
Shaley silt—transition between sand and lower shale ϕ = 22%, So = 7.8, Kmax = 14 md
Shale — minor to no sand
0
2
4m
Petrophysical data derived from core analysis

Figure 17

Viscosity Versus Temperature at 101 kPa. Suffield Upper Manville A Pool



3

STANDARDS FOR HEAVY OIL CLASSIFICATION, AND THERMAL RECOVERY SIEVING,

RESEARCH OF RESERVE CLASSIFICATION STANDARD IN CHINA

Liu Wenzhang
RIPED Beijing, China

ABSTRACT

The heavy oil reservoirs discovered in China have the characteristics of many types of reservoirs. Their reservoir geological parameters and oil qualities greatly differ. According to the characteristics of the heavy oils and reservoirs of China, this paper presents standards of heavy oil classification and thermal recovery criterion and OOIP quality classification.

Considering viscosity as the principal index and gravity as the secondary index, heavy oil can be classified as conventional heavy oil, extra heavy oil and super heavy oil (or natural bitumen). To facilitate international technology exchange, the author has put forward his heavy oil classification considering not only Chinese heavy oil reservoir characteristics but also classification standards used widely throughout the world, especially the classification standard of UNITAR.

This paper studied heavy oil reservoirs based on three situations for steam- injection recovery: 1) present recovery technology, 2) short period of improving recovery technology and 3) long time development of recovery technology. Five groups of parameters were considered: oil viscosity and gravity, pay zone depth, net thickness of reservoir and ratio of net thickness/gross thickness, porosity, initial oil saturation, d v Soi and reservoir factor, permeability. These parameters influence the recovery results mainly by steam injection. After summarizing the experiments in the field, the thermal recovery criterion for the heavy oil reservoir was studied using numerical simulation and physical simulation.

Also presented is the quality classification standard of heavy oil original reserve, which is needed for heavy oil reservoir evaluation.

INTRODUCTION

In recent years, many heavy oil reservoirs have been found in China whose oils were successfully recovered using steam soak method. Until the end of 1986, more than 300 wells with reservoir depths of over 100 meters at Gaosheng, Shuguang 1 zone, Huan Xiling of Liaohe region, and Shan Jiashi field of Shengli region, have been conducted with steam soak. Shallow heavy oil reservoirs of 9 zone in Keramay and Xinjiang also conducted its commerical production by steam soak. The annual production from steam soak in 1986 reached 1.5 million tons. This means China has a good future in thermal recovery.

As well known, steam soak is only the first stage of steam injection recovery which is usually suitable for different heavy oil reservoirs. When changed into steam drive, the process becomes more complicated since the effectiveness of the steam stimulation is strongly influenced by geological parameters and the oil viscosity of reservoirs. Moreover, during this stage, the oil/steam ratio drops rapidly and therefore the economic risk becomes higher. For these reasons, to sieve reservoir conditions is of first importance, before carrying out the feasibility study of thermal recovery. As a result, it is pressing to determine the unified classification standard, thermal recovery criterion standard and reserve quality classification standard for heavy oil. These classifications will then be used to: 1) sieve out (put through), discovered reserves, blocks, or zones, which are suitable for steam injection, 2) complete its evaluation and 3) prepare projects for heavy oil reservoir development and technology of recovery.

Heavy oil classification standard and thermal recovery criterion standard have been studied by many experts of UNITAR, U.S.A. Canada and Venezuela. RIPED of Ministry of Petroleum Industry has also done similar work in recent years. Using numerical simulation, physical model experiments of thermal recovery, and reservoir engineering study methods, RIPED has undertaken feasibility studies of steam injection recovery. These include experimental design of steam soak and steamdrive pilots, steam injection development project and some other related subjects considering several types of Chinese heavy oil reservoir characteristics. The results demonstrated that classification standards of heavy oil, thermal recovery criterion standard and reserve quality classification which were put forward by RIPED in 1985, were appropriate and feasible. Through some complementary studies those classification standards were adopted by the experts from four main heavy oil fields in a symposium celebrated in 1986. All participants agreed to recommend these as national standards.

GENERAL CHARACTERISTICS OF HEAVY OIL

Heavy oil reservoirs found in China have a wide distribution with many types and varieties of depth, from 10 - 2000 m. The bearing formations are predominantly sandstones. Heavy oil characteristics in China are similar to those in U.S.A., Venezuela and Canada; however the heavy oils in China have their own characteristics, as follows:

☐ *1) They contain less light fractions, and much asphalt-resin. Oil gravity and viscosity increase with an increasing content of asphalt- resin.*

Presented in Figure 1-A are the relationships between asphalt-resin and oil gravity (at 20° C) of eight blocks of heavy oil reservoirs of the Sahejie formation and Kongdian formation, low Tertiary; Wang Guantun oilfield, Dagang oil region. Relationships between asphalt- resin and gravity of 35 reservoirs or blocks of Liaohe oil region are shown in Figure 1-B.

The qualities of the heavy oils from the several oil regions change greatly with their asphalt-resin contents. The relationship of asphalt-resin and viscosity (at 50° C) of 39 heavy oil reservoirs or blocks of Gaosheng, Shuguang and Huan Xiling oilfields, Liaohe oil region, are shown in Figure 2. Light fractions of most heavy oils are lower than 10%, with an average of 5%.

☐ *2) Heavy oil's viscosity increases with an increase of gravity, and shows a poor linear relationship.*

Heavy oil reservoir's geological conditions in China are very complicated for they belong to continental sedimentation. The crudes contain a wide range of asphalt-resin. Comparing with heavy oils of other countries, asphalt content of the crudes in China is lower, generally less than 10% (weight). In some cases, it is close to zero. However, the resin contents appear to be higher and consequently the gravity becomes lower and the viscosity higher.

Figure 3 shows the relationship between gravity (at 20° C) and viscosity (at 50° C) of dead oils from 41 oil reservoirs or blocks of Liaohe oil region. It is evident that, in west region reservoirs and east region reservoirs, viscosity increases with increasing gravity. Nonetheless, they are not in a linear relationship.

Figure 4 shows the change of the dead oil viscosity (at 50° C) of several tens heavy oil reservoirs in Shengli oil region, with the gravity at 50° C. Considering the difference of buried depth, reservoirs temperature and gas dissolved in oil for different heavy oil reservoirs, the magnitude of changes of oil viscosity and gravity at reservoir conditions appears to be high.

☐ *3) Viscosity of heavy oil is very sensitive to temperature.*

Viscosity - temperature plots of oils from several heavy oil fields in China are shown in Figure 5. As can be seen, they exhibit similar behavior.

☐ *4) Sulfur content is very low.*

Sulfur content of the heavy oils in China is relatively low, generally less than 0.8%. Table 1 compares the chemical compositions of the two typical heavy oils in China and those in other countries.

☐ *5) Low metals (Ni, V, Fe and Cu) contents.*

The metals content data of heavy oil reservoirs in China is given in Table 2.

☐ *6) Low paraffin content.*

The average paraffin content is 5% and the pour point is very low for most heavy oils from Gaosheng, Shu-1 zone and Huam Xiling, Liaohe oil region; the ninth zone, Xinjiang oil region and Shanjiachi, Shengli oil region. Some heavy oil fields are exceptions, eg. Zhaoyuan and Wang Jiatun oilfields of Dagang oil region, have asphalt-resin content up to 30%, paraffin content 10 - 50%, pour point 15%, gravity 0.9256- 0.9530 and viscosity at reservoir conditions from 125 - 650 cp.

HEAVY OIL CLASSIFICATION STANDARD

Heavy oil classification has a direct relationship to the evaluation of the heavy oil reservoir method. Heavy oil recovery, storage, transportation and refinery are different from those of the conventional light oils. New concepts and new technology need to be established.

Many heavy oil experts have studied heavy oil classification. It was discussed in the First and Second International Heavy Oil and Tar Sands Sumposiums and Experters Symposium organized by UNITAR. Classification standard recommended by UNITAR is given in Table 3. Standard used by Venezuela is given in Table 4. The author has studied heavy oil characteristics of China for many years. Chinese heavy oil classification standard is proposed in Table 5.

The following points are emphasized in the classification standard:

- ❑ *1. To unify Chinese standard with international standard in order for international understandings. To be convenient for reserve evaluation and recovery method research.*
- ❑ *2. To form classification using oil viscosity as principal index and gravity as secondary index.*

The classification standard recommended by UNITAR changed traditional classification method by not taking gravity as principal index but viscosity. This seems to be reasonable and practical. This standard is advantageous for heavy oil resource evaluation and production technology study.

For over ten years, heavy oil in China was named as viscous oil. This took viscosity as classification index and considered the characteristic of high viscosity for viscous oil.

When the oil viscosity is less than 100 c.p. it is better to measure the viscosity based on the bottom-hole sample at reservoir conditions. However, bottom hole samples are not easy to obtain. It becomes practical to measure the dead oil viscosity, since heavy oil contains little dissolved gas, generally not over 103/m^3.

Since heavy oil in China contains lower asphalt and metal and higher resin, its viscosity is high and gravity is low. The gravity and viscosity of some representative heavy oils in China are as follows:

Reservoir Gravity Viscosity (cp, at reservoir T)

Reservoir	Gravity	Viscosity (cp, at reservoir T)
6 reservoirs, Liaohe	0.9159 - 0.9240	100 - 1,000
6 - 9 zones, Xinjiqng	0.923	+ 2,300
Zao yuan, Dagang	0.9256	125
Huan Xiling, Liaohe	0.990	30,000
Fengcheng, Xinjiang	0.940 - 0.962	500,000 - 700,000

In Shengli oil region, the oil viscosity is over 100 cp and its gravity is more than 0.934 (see Figure 5). Hence using the gravity of 0.934 (20°API) as the lower limitation isn't suitable. The recommended heavy oil classification standard used a higher gravity value of API than UNITAR, and the temperature was 25° C instead of 15.6° C (60°F). We emphasized viscosity as principal index, because oil gravity covers a wide range. If the gravity range is not over classification limit, and the viscosity range is over, we still classify the oil according to viscosity.

- ❑ *3. It is practical to combine classification standard with production technology criterion. Heavy oil was divided into three catalogues - conventional heavy oil, extra heavy oil and super heavy oil (or natural bitumen). In doing so, it becomes easier to select suitable production technology.*

Conventional heavy oil: lower limit value of viscosity is 100 cp for dead oil, or 50 cp at reservoir conditions. Upper limit value of viscosity is 10,000 cp, gravity is above 0.9200 (22°API). Conventional heavy oil cannot be recovered by water injection, whereas it can be recovered with good efficiency through steam injection.

Viscous ratio of oil/water is an important factor that influences recovery when using water injection.

Experimental results from high temperature relative permeability measurements demonstrated that the relationship between residual oil saturation (Sor) and viscosity of oil-water was in exponential increasing relation (see Figure 6). For 400, Sor 40%. For $\mu_o/\mu_w >$ 400, Sor > 40 %. The oil viscosity at reservoir conditions is over 50 cp (or dead oil viscosity > 100 cp). Consequently, the displacement efficiency by water injection can be over 60%, and recovery is $\geq$ 35%. According to the recovery prediction by water injection in six oilfields where their viscosities at reservoir conditions are 50-73 cp, the recovery can be over 35%.

We recommend this type of oilfield be produced by steam injection in the beginning.

Extra heavy oil: lower limit value of viscosity is 10^4 cp., upper limit value is 5 x 104 cp., and gravity is over 0.9500 (15°C API).

Steam soak is suitable for this type of heavy oil. Many countries including China have done pilots successfully. When changed into steam drive, it becomes more difficult, and the recovery is dropped down. Oil-steam ratio is also reduced. The pilot results of three-D of high pressure scale physical model obtained by the Thermal Recovery Section of RIPED (Figure 7) indicated that the higher the oil viscosity is, the lower the steam drive would be. The continuous line in Figure 7 represents the pilot result from the same model made by Bursell Company, U.S.A. It shows five pilot results of Kern River oilfield. The dotted line represents our pilot. The author has conducted successful steam drive pilots in oilfields where the oil viscosity is 5 x 10^4 cp. For instance, the viscosity of 92% of 167 projects of steam injection recovery done in the U.S.A. in 1986 is 104 cp., and steam drive got good results. Among ten projects in which oil viscosity is 10^4-5x10^4 cp., five steam soak projects were successful, and the other five steam drive are now at the experimental stage[4]. Before long it will be into commercial production by steam injection in heavy oil reservoirs where the viscosities are 5 x 10^4 cp.

Super heavy oil: Viscosity is over 5 x 10^4 cp., and gravity is over 0.9800 (13° API). This type of heavy oil is immobile at reservoir conditions, and cannot be recovered economically using steam injection. Half of the oil reserves is this type of oil. To recover super heavy oil requires special steam drive technology, such as those being used at the Canadian reservoirs at Cold Lake and Peace River.

☐ *4. The author considered the steam injection technology to have reached a new stage. Thus the upper limit value of viscosity used was higher than the values given by UNITAR and Venezuela.*

HEAVY OIL THERMAL RECOVERY CRITERION STANDARD

It is necessary to screen with a simple method in which oil reservoir is suitable for steam injection, before conducting a feasibility study of oilfield exploitation and design pilot, etc. On the basis of a thermal recovery efficiency analysis for geology conditions of various reservoirs, oil quality and lower limit value of operation conditions were determined, which means thermal recovery screening standard.

Numerous papers concerning screening standard studies have been published. The most noticeable ones are Dr. Zhu Jie[5], Texaco, U.S.A.; Dr. Carlos Borregales[6], Petroleos Venezolanos; Mr. C.S. Matthews[7], Shell Company, U.S.A.; Mr. J.J. Taber and Mr. F.D. Martin[8], U.S.A, as well as the NPC Report[9] of U.S.A. These papers present theories and oilfield experiments. Using these results and our analyses and investigations of the different heavy oil reservoirs in China, project design of steam injection recovery, feasibility study of thermal recovery, and steam drive pilot design for six heavy oil reservoirs were completed. Together with ten subject study papers from RIPED, based on thermal recovery mathematical model and physical model, and steam injection pilot results, guidelines were formulated for thermal recovery criterion standards.

Thermal recovery criterion standards were established by considering only steam injection recovery, including the steam soak and steam flooding. Note that the in-situ combustion was not included. There are many parameters at reservoir conditions that affect the thermal recovery criterion. The author has screened five groups of parameters of reservoir geological conditions which have a close relationship to thermal recovery: 1) Oil viscosity and gravity, 2) reservoir depth, 3) pay zone net thickness and net thickness/total thickness ratio, 4) porosity d, original oil saturation Soi, ϕ x Soi and reserve coefficient, and 5) permeability. Other criterion parameters of reservoir conditions were considered in a qualitative fashion.

Thermal recovery criterion standard should be established on the basis of the thermal recovery technology. It is recommended that the criterion standard take into account present technology, possible technology improvement, and technology development in the future. Also, economical index was mainly based on OSR.

■ 1. Oil Viscosity and Gravity

Steam soak method has been economically successful in reservoirs where the oil viscosity is up to 20 x 10^4 cp.. But for steam dislacement, two criterion that limit values are the lowest and the maximum values of viscosity; gravity is not considered important. Steam flooding requires substantial investment, high cost, and is a complicated technology, hence it is preferable to recover this type of heavy oil by using water injection displacement.

The maximum value of oil viscosity suitable for steam flooding has been increased due to the advance of technology. For instance, in the 70's, the maximum value was less than 1000 cp.; in the 80's it was 5000 cp.. Taber and Martin[8] and experts of NPC of U.S.A.[9] suggest that this value could be 15,000 cp.. Thermal recovery simulation results from RIPED demonstrate that oil viscosity should not exceed 10,000 cp. for thermal recovery based on the available technology. The results also indicate that oil viscosity could be at 50,000 cp. for good reservoir geology parameters such as reservoir net thickness at 10m and OSR of over 0.15. It is predicted that for a reservoir of 50,000 cp viscosity, the recovery could be done by steam flooding, provided that a new system of technology be developed. This includes, for now, drilling, production and oil transportation etc. The steam soak recovery is considered practical. However, for super heavy oil (viscosity over 50,000 cp.) recovery by steam flooding appears to be promising due to the advance of technology.

■ 2. Reservoir Depth

There are low and maximum values of reservoir depths for criterion of steam flood recovery. If reservoir depth is too shallow, steam injection pressure will be too low to exceed fracturing pressure. As a result, recovery is very low. The thermal recovery laboratory at RIPED simulated steam floodings for three oilfields under different temperatures using a physical model. The results (ratio of oil viscosity and residual oil saturation) of the experiments are given in Figure 8. In 1967, the first steam drive of Keramay oilfield, Xinjiang, China, was done in a pay zone that had a depth of 100 m, and a steam- oil ratio up to 12. The steam breakthrough occurred at an injection pressure of 25-30 at. The shallowest depths mentioned in the reference papers [6], [8], and [10] were respectively 61, 91 and 122 m. The shallowest depth was estimated at 150 m, assuming that the injection temperature was 200° C and the injection pressure was 15 at.

The technical difficulties are due to: large heat loss at well bore, determining the steam quality at well bottom, and the casing damage caused by high temperatures. The deepest depth that allows for steam drive process has become deeper and deeper. It can be, for example, 300 ft (915 m), 4000 ft (1220 m) or 5000 ft (1525 m).

Since 1979, RIPED has studied heat insulation technology for deep well bores of 1000 - 1800 m. The designs and experiments of insulation tube and liquids were successful[10]. Physical and mathematical simulation studies for a well of 1600 m depth showed that the heat loss ratio in well bore could be reduced to 11% using well bore insulation, tube type II. This new technology of high efficiency can reduce heat loss to as low as 8%. Figure 9 shows, even for an 1800 m depth reservoir, that well bore heat loss can reduce to 10%. If steam quality at well head maintains at 70 - 80%, it will be at 55 - 65% at bottom in a short period. Several large scale steam soak processes in reservoirs of 1000 - 1400 m (Liaohe and Shengli oil region) or 1500 - 1600 m (Gaosheng oilfield, Liaohe oil region) in depth coincided with our research.

RIPED recommended three grades of steam flooding depth: 150 -1400 m, with available technology; 1600 m, with technical innovation; and with technical development in the future the depth could reach 1800 m. For steam soak, depths could exceed the maximum values by 200 m.

■ 3. Pay Zone Net Thickness and Net Thickness/Total Thickness Ratio

One of the most important conditions for steam flooding is a sufficient depth of pay zone. The pay zone should have interlayers as thin as possible, and the ratio of net thickness to total thickness should be as high as possible. During the steam-injection period (generally 5 - 7 years), the heat injected into pay zone is lost through either the top or bottom zones. In addition, some of the heat is absorbed in the inter layers. When heat loss is great, the steam-zone volume will then be reduced. Consequently, OSR and recovery factor will be reduced.

Using three D and three phase numerical simulation of thermal recovery, we have studied the accumulative heat loss rate for pay zones of different depths. The results are shown in Figure 10. For example, when the steam-injection time is 300 days, the accumulative heat loss is 30%, 40% and 75% for 20, 10 and 5 m depths, respectively. When the steam-injection time is 1500 days, the accumulative heat loss is 50%, 70% and 84%. It is evident that heat loss is great for depths less than 10 m.

Accumulative OSR's were also calculated at different reservoir depths, and a net thickness/total thickness ratio of 1, 0.7 and 0.5 respectively. The results are shown in Figure 11. If OSR is maintained at 0.15, the following conditions must be satisfied: pay zone net thickness 10 m, net thickness/total thickness ratio 0.5; high values of porosity and movable oil saturation Ws, otherwise, OSR will be lower than the economical limitation.

It was noted that in other countries the thinnest thickness permissible for steam flooding is 6 - 8 m [11]. Jiang et al of RIPED studies the feasibility of applying steam injection process to pay zones of only 3 - 6 m thickness. The conclusion of their study indicated that it is possible to use steam injection for pay zones of 5 - 6 m thickness, if the investment and design are optimized. Because of the present economic situation, it is considered a low priority to apply this technology to this type of reservoir.

Hence, it is recommended that the conditions for steam flooding be 10 m or higher for pay zone thickness and 0.5 or higher for net thickness/total thickness.

■ 4. Porosity ϕ, Initial Oil Saturation SOI and Reserve Factor.

The influence of porosity and mobile oil saturation Δs(= Soi - Sor) on the oil- steam ratio (OSR) for steam flooding were calcualted. Δs value was calculated from Figure 6, Figure 8 and SOI for a certain reservoir, or Δs were obtained from the physical model experiment (see Figure 12). It was found that the higher the porosity, the higher the OSR. When the pay zone thickness was increased, OSR could be improved. For a pay zone thickness of 10 m, $\Delta s = 0.35$, and the economical limitation = OSR + 0.15, the lowest value of porosity allowed is 0.20.

As shown in Figure 13, the higher the Δs is, the higher the OSR. This indicates that Soi, the lower saturation of oil, will be higher and the residual oil saturation (SOR) will be lower. If the limiting value of ϕ is 0.20, Δs must be over 0.38, Soi>50%, or $\phi \times \text{Soi} \geq 0.10$. As a result OSR can reach 0.15. If the limiting value of porosity is 0.35, then Δs must be over 0.25, Soi≥40%, OΣP≥ 0.15, op $\phi \times \text{Soi} \geq 0.14$.

In references 5, 6, 7, 8 and 9, Chieh Chu etc. analyzed the economic risk of steam flooding, and recommended that the lowest porosity be 0.20, the lowest Soi before steam flooding 0.50 or d x Soi 0.10, and the reserve factor limit be 700 m3/hc.m..

■ 5. Permeability and Value kh/μ

During steam flloding, the injection pressures should belower than the fracture pressure in order to maintain a sufficiently high steam-injection rate. A low steam-injection rate causes substantial heat losses in well bore and reservoir and therefore results in low OSR. Figure 14 shows the influence of the injection rate on OSR. As can be seen, there is an optimum injection rate for each reservoir. For high oil viscosity, the permeability has to be high enough to maintain suitable injection rate.

Chieh Chu etc. [5,6,7,8,9] indicate that the lower limits of the permeability could be 100, 200 and 250 md, and the conduction factor $kh/\mu > 5 - 100$ md.ft/cp. (1.5 - 30 md.m/cp). U.S.A. has experienced the success of applying steam- injection process to reservoirs of permeability of 200 md. The fracturing technology was used as additional engineering. In China, we recommend that the lower limit value of permeability be 250 md. As for, kh/μ, the values of k, h and μ should be selected accordingly to avoid contradictions.

■ 6. Other Factors

There are five parameters of geological characteristics that must be regarded other than the five parameters group that was discussed above.

❑ *1) Reservoir Rock*

Sandstone reservoir is most suitable for thermal recovery. The fractured sandstones, however, may cause steam breakthrough. Steam flooding is not suitable for fractured limestone. This is because very low heat efficiency is achieved in reservoirs.

❑ *2) Reservoir Pressure*

Saturated steam can cause a small volume of steam zone at high reservoir pressure during steam flooding. In China, it is necessary to apply steam flooding after steam soak process which reduces the reservoir pressure. This is because in China, the depth of the heavy oil reservoirs is relatively deep, and most of them have not been treated with conventional oil recovery methods.

❑ *3) Small Dip Angle*

According to RIPED lab experiments, when the dip angle is over 10, steam zone gravity overburden is aggravated, and this causes low recovery factor.

❑ *4) Good Communication between Injection and Production Wells*

High heterogeneity of pay zone and poor communication between injection and production wells by zone tip, lacuna, or fault, are not beneficial for production.

❑ *5) The reservoir with bottom water or cap gas generally is not suitable for steam flooding. It requires appropriate strategy to operate, unless one adopts adequate control steam flooding.*

■ 7. Limitation of OSR

OSR is the most important economic index of steam flooding. In many reports, OSR limitation is taken as 0.15 or 0.125 depending on the international oil price. The technical and economical situations are different in China. RIPED has studied for severals years the economic index of thermal recovery, and the relationship between OSR and the production cost of four oilfields. The results are shown in Figure 15. The economic analysis of the four oilfields indicate that the higher the OSR is, the lower the production cost. The production cost is very sensitive to OSR. In view of the current oil price, the best oilfield is D with an OSR of 0.125, and the worst oilfield is C with an OSR of 0.14. As steam-injection technology in China continues to develop, we choose the OSR limit to be 0.15, as our criterion standard.

The recommended reservoir criterion standard of steam-injection recovery is presented in Table 7.

HEAVY OIL RESERVE QUALITY CLASSIFICATION STANDARDS

To benefit from a good quality reservoir being put in production, a program of oil development and evualtion of the grade of reserve should be implemented. Heavy oil reserves should be classified not only according to the reserve level of the proved reserve, (such as proved reserve, controlled reserve and potential reserve), but also according to the quality of reserve. In doing so, it would be more viable to produce oil from reservoirs of good quality.

Geological parameters for both reserve classifications and thermal recovery criterion standards are generally the same. Hence, those standards given in Table 7 can also be used as the heavy oil reservoir evaluation standard.

The high quality reserve is the conventional heavy oil which can be recovered successfully using the current technology and the best reservoir of development effect and economic efficiency.

As for the second class reserve, (median reserve), most of the reservoir parameters are suitable for thermal recovery. Some parameters are, however, rather poor - such as deeper depth and high viscosity. This type of reservoir relates to the extra heavy oil, for which the thermal recovery method needs technology innovation. Perhaps in recent years, the existing technical difficulties will be resolved.

Third class reserve (bad reserve) belongs to the natural bitumen or thin pay zone reservoir with bad physical quality and depth over 1600 m. This type of reservoir requires advanced thermal recovery technology and has bad economic efficiency. Thermal recovery method needs a technology development.

The fourth class reserve is not adequate for steam-injection recovery.

CONCLUSION AND RECOMMENDATION

☐ *1. This paper presents heavy oil classification standards in China and criterion standards of reservoir conditions for steam-injection recovery (including steam soak and steam flooding processes). It also includes the classification standard of heavy oil originally in reservoir.*

☐ *2. The three standards were determined based on the research papers of experts and petroleum organizations in the world. They also take into account the heavy oil reservoir conditions and technical - economic conditions in China.*

☐ *3. These three standards have been studied and compared with some oilfields' development design. Experts from Liaohe, Xinjiang, Shengli and Nanyany oilfields considered these standards to be practical, and recommended these as the unified criterion standards for heavy oil recovery in China.*

☐ *4. For certain reservoirs, feasibility studies of thermal recovery must be undertaken followiong primary criterion, especially for a reservoir whose parameters do no completely conform to the criterion standards.*

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Table 1
Heavy Oil Chemical Component

Country	Oilfield	Geological time	Gravity	Element %						Component %		
				C	H	S	O	N	C/H	Oil	Resin	Bitumen
China	Gaosheng, Liaohe	Shalhejie Formation Low Tertiary	0.94 - 0.96	85.7	11.7	0.55	-	0.72	0.68	-	45.5	3.3
	Chong 1 well and Feng cheng zone, Xinjiang	Low Cretaceous Upor Juriasic	0.9656	86.6	19.4	0.31	-	0.51			56.7	5.7
Canada	Athabasca	Cretaceous	1.015	83.6	10.3	4.6	1.0	0.5	0.68	43.49	23.39	18
	Cold Lake		0.994	82.9	10.7	4.5	1.5	0.4	0.65	53.57	28.32	15
	Peace River		0.026	82.9	10.2	5.9	1.6	0.5	0.58	50.00	30.50	19.5
Venezuela	Jobo	Oligocene	1.020		-	3.0	-	0.6	-	-	25.4	8.6
	Laguna	Tertiary	0.989	-	-	3.7	-	0.5	-	-	-	7.3
U.S.A.	Tar Sand Triangle	Permian	0.992	84.0	10.1	4.4	1.1	0.46	0.69	-	-	26.0
	P.R.	Triassic	0.993	84.4	11.0	0.75	2.2	1.0	0.64	-	-	16.0
	Remolanga	Permo-triassic	0.990	87.1	11.2	0.5	1.2	0.7	0.66	41	33.0	16.0

Table 2
Metal Content of Some Heavy Oil Fields

Metal contains	Gaosheng	Wang Guantun	Yangsanmu	Gu Dao	Feng Chengzone	Shan Jiashi
Nei	122.5	91.5	25.8	16.6	33.3	55.5
V	3.1	0.5	0.9	2.5	1.03	2.5
Te	-	-	-	-	15.3	17.6
Cu	-	-	-	-	24.3	-

Table 3
Classification Criterion of UNITAR

Classification	First Index	Second Index	
	Viscosity (cp)	Gravity at 60°F (15.6°C)	API at 60°F (15.6°C)
Heavy Oil	100 - 10,000	934 - 1000 kg/m^3	20 - 10
Bitumen	> 10,000	> 1000 kg/m^3	> 10

Table 4
Classification Criterion of Venezuela

N	Crude Icind	Classification Criterion
1	Heavy oil	1. Gravity 0.934 - 1000 (10° API - > 20° API) 2. Maximum Viscosity 10,000 CP
2	Extra heavy oil	1. Gravity > 10,000 (> 10° API) 2. Maximum Viscosity 10,000 CP
3	Bitumen	1. Gravity > 1000 (> 10° API) 2. Viscosity > 10,000 CP

Table 5
Chinese Heavy Oil Classification Criterion (recommended by author)

Heavy Oil Classification	First Index Viscosity, cp	Second Index Gravity (20°C)
Heavy Oil (conventional heavy oil)	50 or 100 - 10000 (in reservoir)	> 0.9200 (22° API)
Extra Heavy Oil	10,000* - 50,000*	> 0.9500 (17° API)
Super Heavy Oil (Natural Bitumen)	> 50,000	> 0.9800 (< 13° API)

* Refers to viscosity of dead oil at reservoir temperature.

Table 6
Criterion for ϕ, SOI, Etc. by Chieh Chu

N	Author	ϕ	Soi	ϕ x Soi	Reserve Factor
1	Chieh Chu	> 0.20	> 0.40	> 0.08	-
2	Carlos	-	≥ 0.50	-	> 645 m^3/ha•m
3	Matthews	> 0.20	> 0.40	-	-
4	Taber, Martin	-	> 0.40	> 0.08	645 m^3/ha•m
5	NPC	≥ 0.20	-	≥ 0.10	-

Table 7
Steam Flooding Sieving Criterion and Heavy Oil Reserve Classification Criterion Recommended by Author

Parameter group	First Class on available technology	Second Class on technology improvement in recent period	Third Class Waiting for technology development	Fourth Class not suitable for steam-injection recovery
1. Crude viscosity (at reservoir T)	> 50 - 10000	> 50000	50000	
Gravity	0.9200	0.9500	0.9800	
2. Formation depth	> 150 ≥ 1400	> 150 ≥ 1600	≥ 1800	
3. Net thickness of Pay	≥ 10	≥ 10	≥ 5	≥ 5.0
Net/Total thickness ratio	> 0.50	> 0.50	≥ 0.50	> 0.5
4. ϕ	> 0.20	≥ 0.20	≥ 0.20	> 0.20
Soi	> 0.50	> 0.50	≥ 0.40	> 0.40
ϕ x Soi	≥ 0.10	≥ 0.10	≥ 0.08	> 0.08
Reserve factor 10MT/km^2•m	> 10.0	> 7.0	> 7.0	> 7.0
5. Permeability (md)	≥ 250	≥ 250	≥ 200	> 200

Figure 1-A
Relation Between Asphalt-resin Content and Gravity of Dead Oil of Kongdian Pay Zone of ShaHejie Formation, Wnag Guantun Oilfiled (Parraffin 12-23%)

Figure 1-B
Relation Between Asphalt-resin Content and Gravity of Dead Oil of Heavy Oil Reservoir, Liaohe Oil Region (Parraffin 1.4-12%)

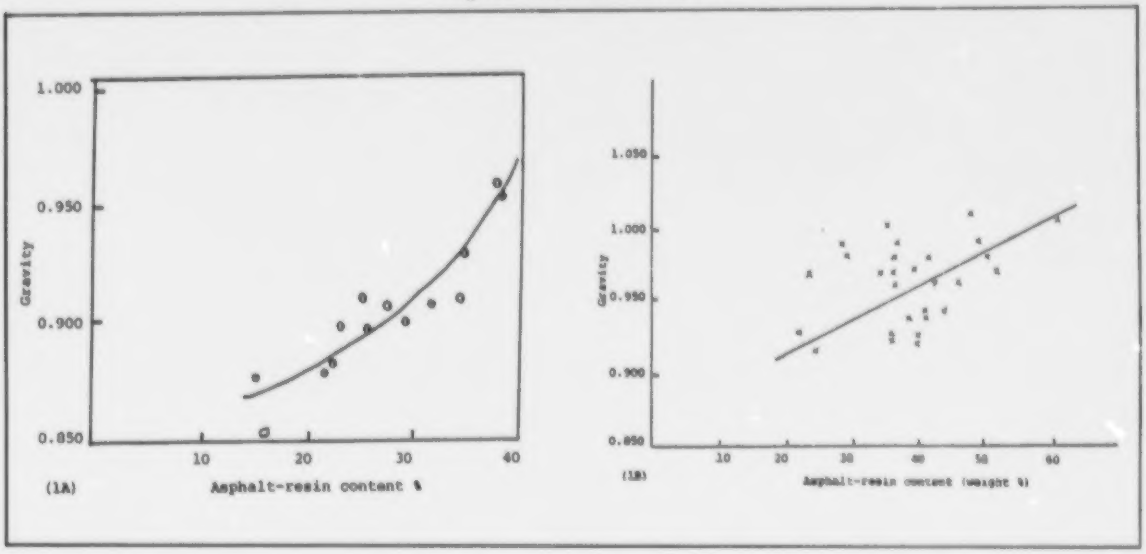


Figure 2
Relation Between Dead Oil Viscosity (at 50° C) and Asphalt-resin content of 39 Heavy Oil Reservoir (or Blocks), Liaohe Oil Region

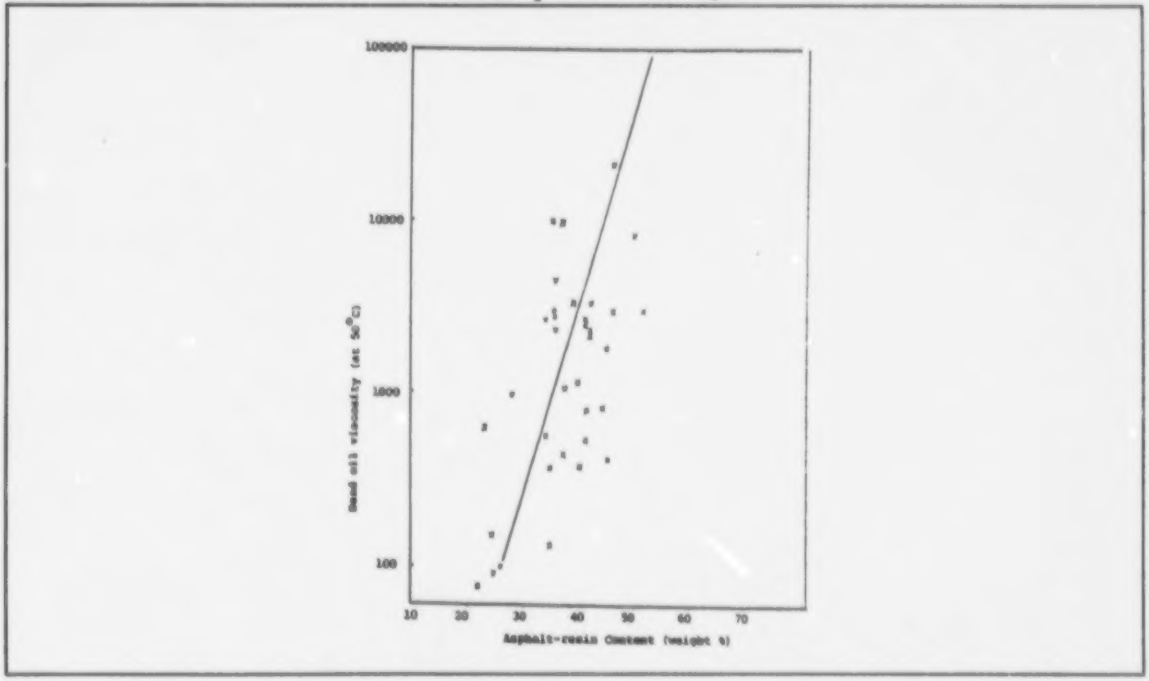


Figure 3
Relation of Crude Oil Viscosity and Gravity of 41 Reservoirs or Blocks, Liaohe Oil Region

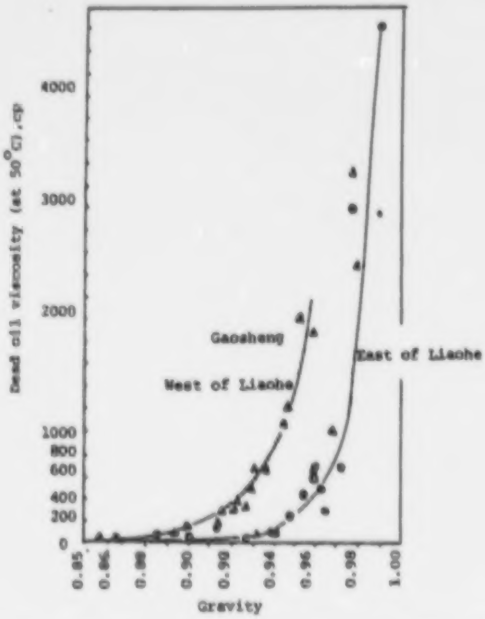


Figure 4
Relation of Crude Oil Gravity at Surface and Viscosity at Reservoir condition, Shengli Oil Region

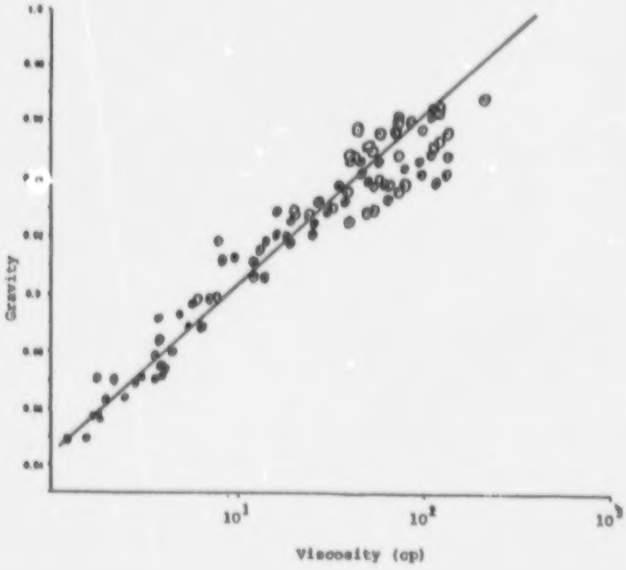
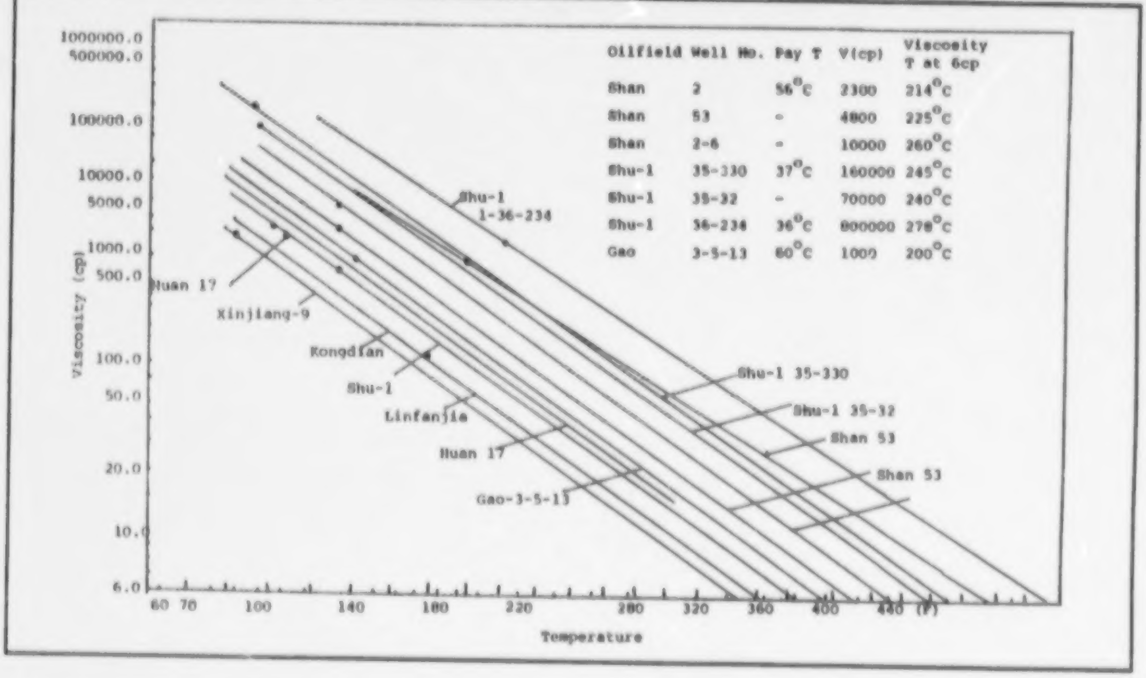


Figure 5
Viscosity-Temperature Curves of Several Heavy Oil Reservoirs in China



Oilfield	Well No.	Pay T	V(cp)	Viscosity T at 6cp
Shan	2	56°C	2300	214°C
Shan	53	-	4800	225°C
Shan	2-6	-	10000	260°C
Shu-1	35-330	37°C	160000	245°C
Shu-1	35-32	-	70000	240°C
Shu-1	36-234	36°C	800000	278°C
Gao	3-5-13	60°C	1000	200°C

Figure 6
Residual Oil Saturation vs. Oil-Water Viscosity by Water Flooding (from Reltive permeability experiment)

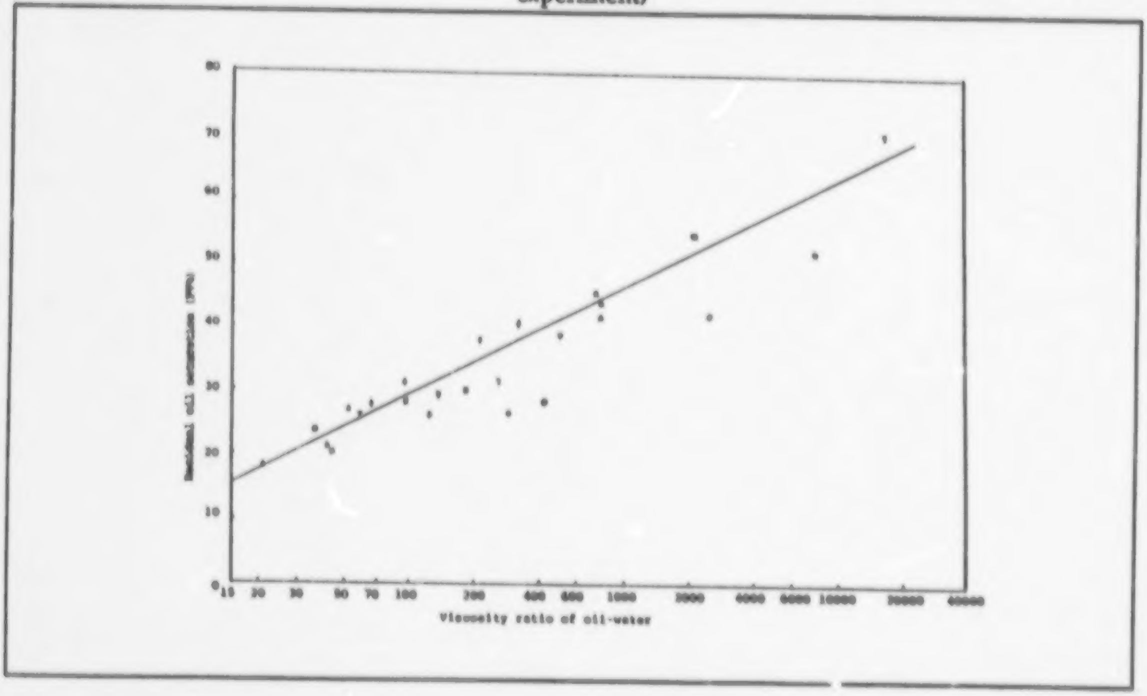


Figure 7
Crude Oil Recovery vs. Viscosity by Steam Flooding

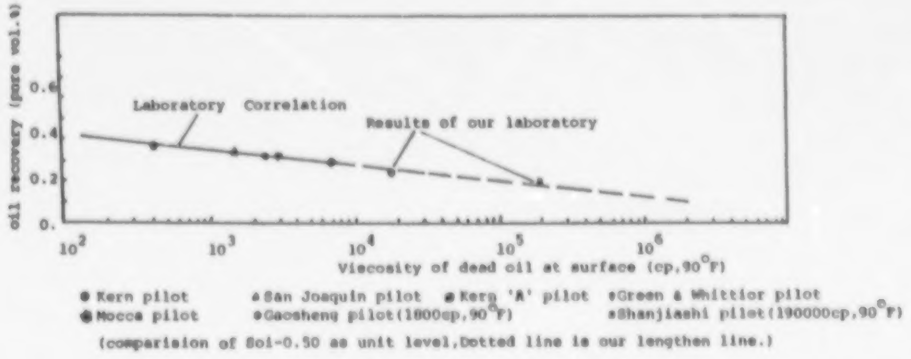


Figure 8
Residual Oil Saturation vs. Viscosity by Steam Flooding

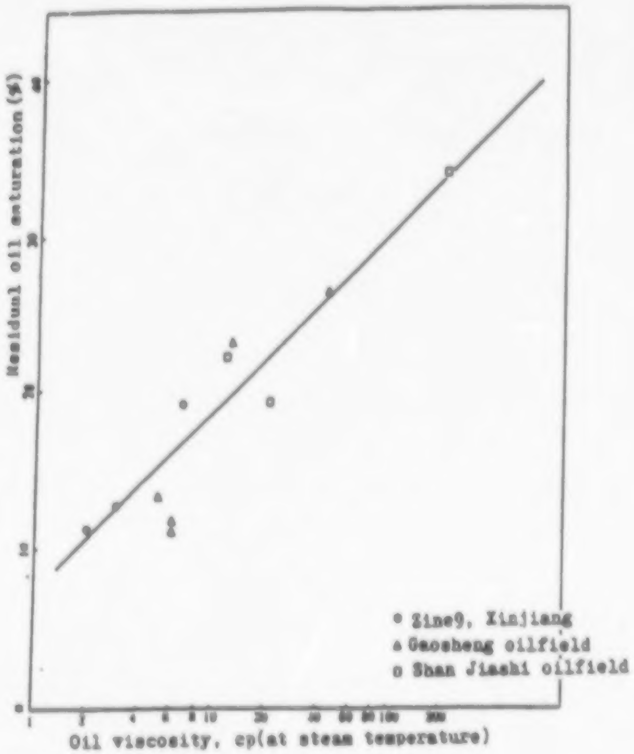


Figure 9
Heat Loss at Well Bore and Steam Quality Loss for Reservoir of Different Depths

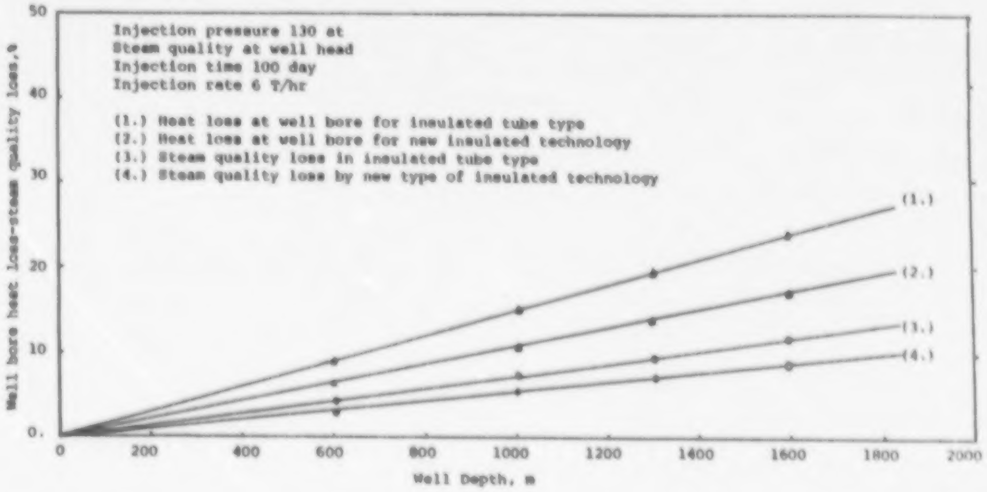
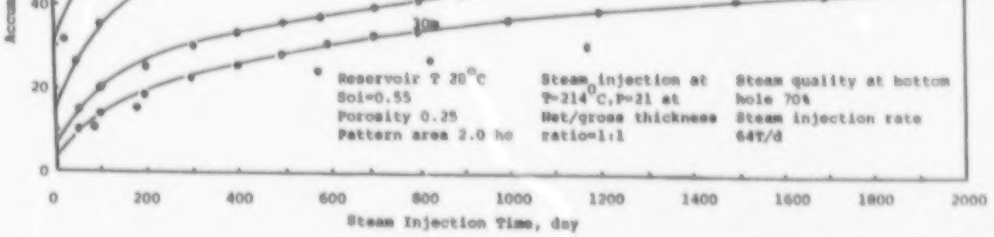

Injection pressure 130 at
Steam quality at well head
Injection time 100 day
Injection rate 6 T/hr

Figure 10
Accumulative Heat Loss Following Steam Injection Time and Pay Zone Thickness


Reservoir T 20°C
Soi=0.55
Porosity 0.25
Pattern area 2.0 ha

Steam injection at
T=214°C,P=21 at
Net/gross thickness
ratio=1:1

Steam quality at bottom
hole 70%
Steam injection rate
64T/d

Figure 11
Influence of Pay Zone Thickness to Oil-Steam Ratio

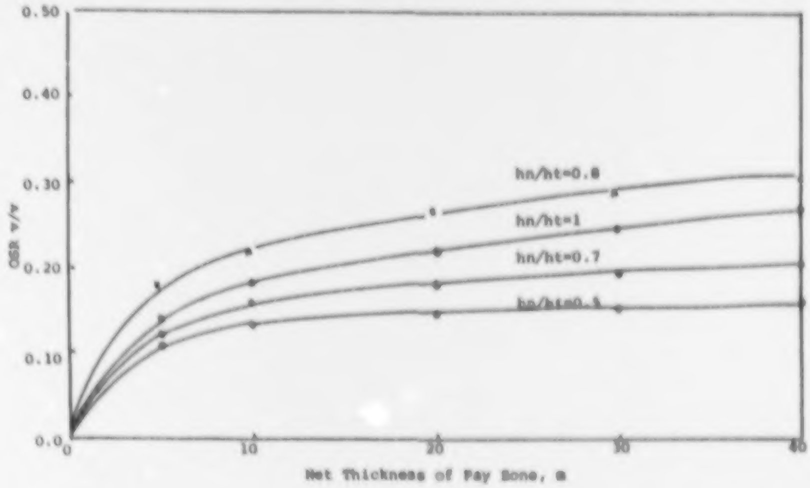


Figure 12
Porosity vs. OSR

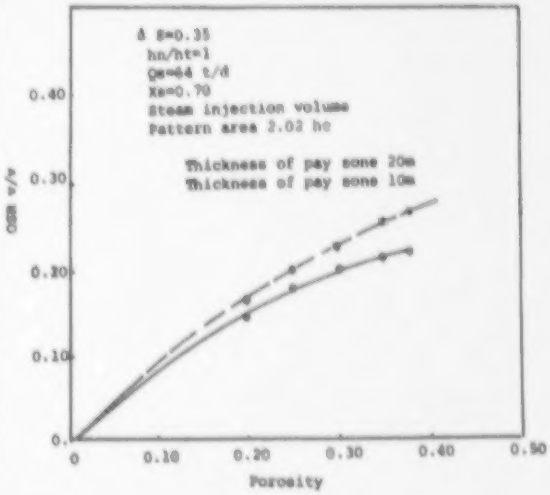


Figure 13
Influence of Movable Oil Saturation to OSR

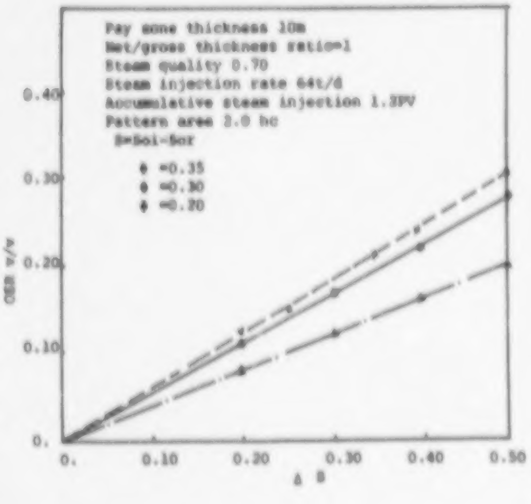


Figure 14
Influence of Steam Injection Rate to OSR

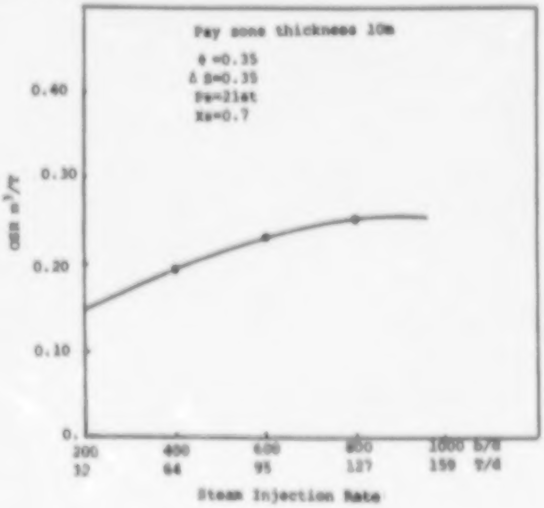
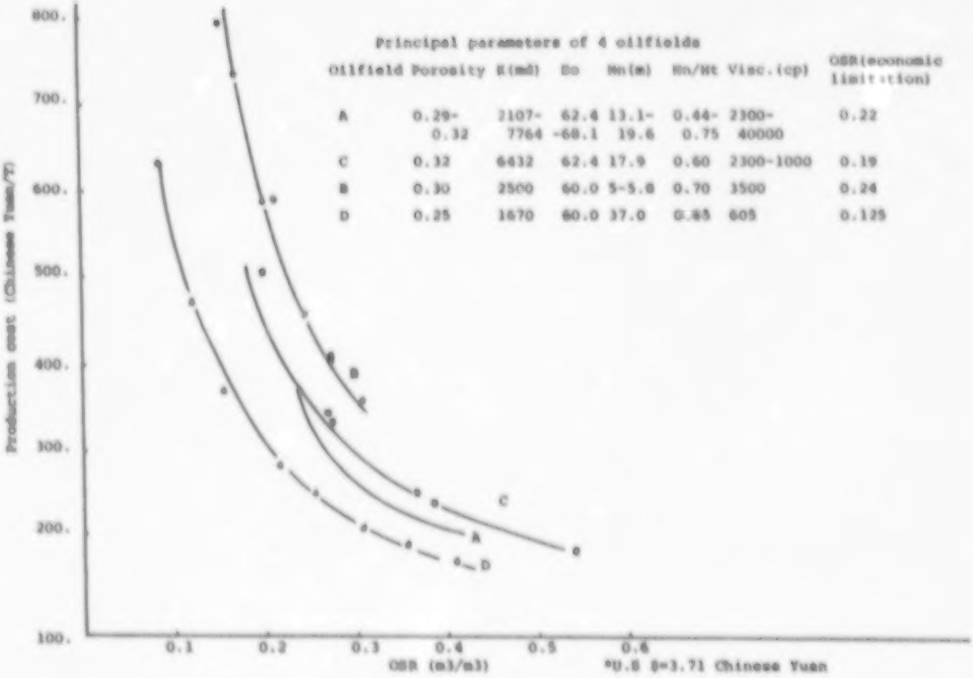


Figure 15
OSR vs. Production Cost of 4 Oilfields



Principal parameters of 4 oilfields

Oilfield	Porosity	K(md)	So	Hn(m)	Hn/Ht	Visc.(cp)	OSR(economic limitation)
A	0.29- 0.32	2107- 7764	62.4 -68.1	13.1- 19.6	0.44- 0.75	2300- 40000	0.22
C	0.32	6432	62.4	17.9	0.60	2300-1000	0.19
B	0.30	2500	60.0	5-5.8	0.70	3500	0.24
D	0.25	1670	60.0	37.0	0.65	605	0.125

4

WELL COMPLETIONS FOR HEAVY OIL PRODUCTION

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1. INTRODUCTION

There has been a substantial increase in the amount of heavy oil production within Canada over the past 20 years; from a low level to the current production level of 33,000 m^3/d. This accounts for 14% of Canada's oil production. There naturally has been an associated increase in the number of heavy oil wells, with the current number of active wells approaching 7000. For the purpose of this paper, heavy oil will be defined to have a gravity less than 24°API. Where a more accurate definition is required, the specific API gravity will be provided.

The location of heavy crude reserves in Alberta, Canada are shown in Figure #1. Also shown on this figure are the approximate ranges for the depth of each major deposit. This varies from the surface outcropping of the Athabasca deposit to a depth of 950 m at the Lloydminster deposit.

Five principal types of reservoir recovery processes are employed on heavy oil reservoirs in Canada; primary depletion, waterflooding, cyclic steam stimulation, steam drive and combustion drive. Although there are many variations of the above processes, this paper will apply the preceding categorization to the classification of heavy oil injection and production wells. The depth of experience within the Canadian industry on each of the five reservoir processes varies. Specific projects have levels of experience that approximately correspond to their size. This paper will define pilot projects to have typically fewer than 50 wells, commercial projects generally more than 200 wells and demonstration projects, approximately 50-200 wells. For the primary depletion, waterflood and cyclic steam stimulation well types there is a wide range of pilot, demonstration and commercial plant experience. This is also true to a lesser extent for steam drive wells. However, in the case of combustion drive wells, experience is limited mainly to pilot scale operations with the exception of several demonstration size projects.

The basis for heavy oil production well completions originates from conventional oil and gas well completions. The problems and constraints of conventional and heavy oil well completions are similar with the key exception being that oil viscosity is significantly different. For comparison at a nominal reservoir temperature of 30°C, a conventional medium gravity crude of 32°API has a dead oil viscosity of 5 cp, while a 10° API heavy crude has a viscosity of 100,000 cp. Primary production of such a heavy crude would not be possible. The most common method to lower such high viscosities is to increase the temperature of the formation and hence the produced fluid. In the above example the viscosity of the heavy crude can be lowered to 5 cp by heating to 235°C. It follows that controlling the temperature of the reservoir fluids may improve the economy of the recovery process. It is also evident that temperature and oil viscosity are two important design factors of heavy oil production wells.

The completion design for heavy oil injection wells is also related to conventional practice, with the complicating factors in this situation being that of high temperatures and cyclic injection/production operation.

For the purposes of this paper the term well completion will mean the design, installation and operation of casing, cement, tubing, liners, packers, instrumentation, wellheads and pumping systems. This is a somewhat expanded definition from that commonly used and includes topics that fall under the disciplines of drilling, workover and production engineering.

This paper will provide some guidelines on the design and operation of heavy oil production and injection wells. The information presented is primarily based on the well operations at AOSTRA affiliated projects. The diverse nature of the 10 major AOSTRA projects in this specific area has produced many worthwhile observations. A list of the number of wells and principal reservoir recovery processes for each of the 10 projects is provided in Figure #2. In many of these projects there have been other short term, small scale reservoir processes tested. Only the principal reservoir processes are listed. A number of specific examples will be cited to illustrate the practical application of the guidelines. Also included will be a discussion of the methodology to design, install, operate and evaluate heavy oil well completions.

2. THE DEVELOPMENT PROCESS

The development of the proper well completion for a particular situation usually requires field testing of a number of alternatives and refinements. Even major commercial scale projects in operation for a number of years continue to investigate improvements to their well completions.

A logical methodology can improve the efficiency and reduce the time required to develop a proper well completion. Such a framework is provided in Figure #3. The first and last components of the process; setting objectives and reviewing performance, are highlighted, as they are frequently omitted or poorly conducted. Adherence to the complete design process is particularly important on projects with new reservoir processes, where several different completion types will probably be evaluated.

Detailed discussions of each of the components identified in Figure #3 will be presented in the subsequent sections of this paper.

3. SETTING OBJECTIVES AND PLANNING WELL COMPLETIONS

This section will address the first 5 components of the development process presented in Figure #3, starting with the setting of objectives and concluding with the selection of a design.

Setting objectives, component #1, is a critical step in the development process. The most important objectives are those related to the required production/injection capabilities. Hard data or estimates must be obtained or developed for flowrates, pressures, temperatures, and cyclic variations. The other objectives will vary in importance according to the specific nature of the project. Commercial scale projects might emphasize costs, while a pilot project might heavily weight considerations for future flexibility.

Setting the objectives for a particular well completion task is a multidisciplinary effort. Input is required from geologists, reservoir engineering, project management, operations personnel and well completions engineers. The objectives should be updated as required to keep the development process on track.

The completions engineer must also disseminate the findings of his design work to the other personnel involved with the project according to good project management practices. Most important here is to communicate limitations in production/injection capabilities to reservoir engineering personnel.

Input data, component #2, must be carefully reviewed for its validity prior to inclusion in the planning process. This is discussed in greater detail under the section, evaluation of well completion performance.

The design process, component #3, should be governed by the following three rules:

1. Keep it simple. Try the easiest way first. Put as little equipment down the hole as possible.

2. Plan for a second life on pilot project wells, this includes a combination of longevity and a capability for recompletion.

3. Try to progress from existing designs in a measured, methodical way. An example of this is provided in the section, evaluation of well completion performance.

In reviewing the proposed designs against the objectives, component #4, it is important to consider all factors and designs simultaneously using a consistent method. For complicated situations a weighted numerical technique should be employed.

The final result of the planning process is a well completion plan, component #5. The plan should include a list of activities, a schedule and the associated costs.

4. EXAMPLE WELL DESIGNS

The following examples illustrate the approaches to well design utilized by several AOSTRA affiliated projects. In every case there were project specific factors that resulted in unique designs. If a progression in well designs has occurred on a particular project, the most recent proven design is presented. These well completions are intended as a starting point for application to other projects, based on the development process outlined in this paper. The examples have been categorized according to the type of reservoir process and whether or not sand production is experienced. The summary comments provided on installation and operating experience highlight the major findings, but do not explore the complete details that are available.

Shell PRISP

This pressure cycle steam drive project employed three types of production well completions; open hole-gravel packed, open hole-slotted liner and cased hole-perforated. The project has been successfully operated since 1979 and has recently been expanded to a commercial scale operation.

All three types of completions were successful. There have been no major problems. Minimal sand production was experienced in all cases. The production well completion in Figure #4 shows a cased and perforated well from the pilot project. This well completion type was incorporated into the recent commercial development. Minor problems were restricted to several wells with low cement tops, the selection of pump metallurgy and optimization of pump efficiency. Corrosion in the production wells has been much lower than predicted. No examples of formation movement and only one instance of casing deformation have been noted.

The injection well completion shown in Figure #5 has operated satisfactorily over the entire life of the pilot project. No major problems have been observed.

Bow Valley ABC Project

The reservoir process on this project is based on cyclic steam stimulation, but with significant variations from the norm. Various combinations of CO_2 and an ionic additive have been injected in conjunction with experiments on superheated steam.

Sand production has varied with the particular reservoir process employed. The most severe sand production occurs during the blowdown period of the first few cycles, which is typical for the Cold Lake area.

The wells were drilled from pad layouts, using deviated drilling techniques and were completed with conventional perforated completions. Bottomhole pump performance has been satisfactory, in part due to the 10 m sump. The production well completion is shown in Figure #6.

The insulated tubing employed during the superheated vapour injection tests experienced mechanical failures, due to a reduced ability to withstand "cold kill" operations, inherent when the tubing was designed to operate to a maximum temperature of 40°C. "Cold kill" occurs when cold fluids are injected into a hot string or when hot fluids are flowed up the casing-tubing annulus of a cold string.

The project commenced operation in late 1984 and is currently in the early phase of operation on a new pad of wells.

Canterra Kearl Lake

This project, located in the Athabasca deposit, produces from the McMurray formation. The producing formation is completely unconsolidated, which has caused very severe sand production problems on a number of the other projects in this area. The reservoir process is based on fracturing to develop injector to producer communication and is then followed by a steam drive.

A typical production well completion is shown in Figure #7. The upper production interval in this example is completed with a wire-wrapped sand screen. Proper selection of the gap width was obtained from a review of theory, lab tests and most importantly, field experimentation. The current gap width selection criteria is one of partial sand retainment. The project has also employed with good success, the use of "slurry packs". In this operation gravel pack sand is injected into the completion interval above fracture pressure. This sand is then retained by a wire-wrapped screen. The lower production interval in the example well employs this type of completion. Acceptable performance has been observed with both types of sand control; solitary wire- wrapped screens, and a "slurry pack" retained by a wire-wrapped screen.

More detailed appraisals of these two sand control techniques in addition to the effects of open hole vs perforated completions are currently being conducted. Improvements in liner hanger assemblies and packoffs are also being investigated. It has also been established that heavy polymer fluids are beneficial in controlling sand sloughing during workovers.

Initial phases of the project experienced casing deformation in the production intervals. The deformation has been tentatively related to cement integrity, stimulation practices and the totally unconsolidated nature of the formation. Recent phases of the project have used heavier walled casing of larger diameter in an attempt to control this situation. Stimulation practices have also been adjusted.

Injection well design utilizes perforations and isolated dual zones. Sand influx during upset conditions is prevented by trickling in small amounts of fluid.

The project has been in operation since late 1981 and can be considered to have reached acceptable solutions for well completions problems in the Athabasca deposit.

Norcen Bodo

This project is located in the Lloydminster heavy oil area and produces 12°API oil from the McLaren zone. Initial reservoir conditions are such that primary recovery is utilized and then followed with steam stimulation. A cased hole type production well completion used on the project is shown in Figure #8. Open hole type completions were also employed.

Problems occurred during the cementing of the wells, when the upper sections of cement became gassified due to influx from a gas zone. Poor to non-existent cement bonds were measured. Upon evaluation, a program to confirm the integrity of the cement was implemented. After running initial casing deformation surveys the wells were steam stimulated in a specific order. Several of the most poorly cemented wells used insulated tubing. The other wells were steamed with bare tubing, starting with the well with the best cement and proceeding to the worst. Measurements after the first steam cycle indicate no deformation. The cement bond is now expected to be adequate to withstand thermal stimulations.

During the primary production phase of the project, the perforated completions demonstrated superior production performance, with generally acceptable levels of sand production. In most cases, wire-wrapped screens were not necessary on the perforated wells during primary production. All open hole wells employed wire-wrapped screens. The evidence is quite conclusive that the wire-wrapped screens held back oil production during the primary depletion phase.

Since steam stimulation has commenced, all wells have been equipped with wire-wrapped screens, with little observable difference in production rates between the open and cased hole completions.

The project has been in operation since early 1985. The well completions are considered to have been successful.

Alberta Energy Company - SHOP Project

The primary reservoir process on this project has been wet combustion in the Upper Mannville formation, following an initial period of primary production.

The production well completions shown in Figure #9 have been very successful. No major operating problems have been observed with these well completions. No production wells have been lost to firefront breakthrough or excessive corrosion, even with high produced fluid O_2 concentrations. Sand production has been very minimal.

The injection well completion shown in Figure #10 has also been a success. The well experienced gradual formation plugging from compressor lubricating oil and rust that was transported during the water injection part of the cycle. A special cleaning program of solvents and acids was developed to remove the formation damage.

The project commenced operation in 1981 and continued wet combustion until 1987.

Current Design Guidelines

The wide variety of well completion types as illustrated precludes any absolute design criteria. However, some general "rules of thumb" have been utilized on AOSTRA projects:

1. Select a casing grade and coupling type that are certain to withstand the thermal cycling. Current practice is to use L-80 casing with a modified buttress thread coupling.

2. On pilot projects a casing size one larger than the minimum is recommended. For example if a 139.7 mm O.D. casing is possible for a perforated completion then use a 177.8 mm O.D. casing. This gives the flexibility of installing liners, screens, pumping equipment and downhole instrumentation to meet revised objectives.

3. A reasonable sump of approximately 10 m should be incorporated into all thermal production wells, allowing the pump to be landed below the production interval. This encourages improved pump efficiencies.

4. Class G cement with 35% silica flour is commonly used on wells subjected to steam temperatures. Fireflood wells usually incorporate silica-fondue cement over the production/injection interval.

5. Wire-wrapped screens with gap widths sized for partial particle retainment have been successfully deployed in unconsolidated formations.

6. Properly designed gravel packs can be effective sand control techniques.

5. INSTALLATION AND OPERATION

All major well completions or workover activities require the preparation of a detailed program. This is particularly important to ensure that all necessary tools and equipment are available when required. The more complex or critical the activity the greater the detail required. To illustrate the possible extent of a detailed program an example of the BP Marguerite Lake O_2 injection well cleaning procedure is cited. This document contains 42 distinct procedures and involves a very formal approval and reporting process.

It is also important to maintain high standards on the makeup and running of casing and cementing procedures. The integrity of many wells has suffered from the attitude that drilling shallow, low pressure formations does not demand the best equipment and personnel.

During the operating phase of the project it is important to document all well operations and workovers. Without this information the evaluation of well performance is impossible.

6. EVALUATION OF WELL COMPLETION PERFORMANCE

This task has proven to be the most challenging of all the aspects of well completions activities. When evaluating a specific parameter of well design, for example, sand control techniques, the evaluation of the evidence may show:

1. Distinct differences between alternatives.
2. Confirmation of negligible difference between alternatives.
3. Unknown results due to the influence of other parameters such as the reservoir process or inadequate measurements.
4. Unknown results due to the use of a well completion method on an unrelated problem. For example, if a well is suffering from wellbore impairment, changing the pump will have no effect..

Unfortunately the majority of well completions evaluations produce unknown results as per items #3, and 4 above. Great care must be taken in designing comparison tests to obtain definitive results.

The performance data considered essential for a complete analysis of a thermal production well are:

- ☐ *production rates; oil, water, casing gas, tubing gas*
- ☐ *wellhead pressures and temperatures*
- ☐ *bottomhole pressure and temperature*
- ☐ *pump speed and stroke length*
- ☐ *inflow performance tests.*

Unfortunately all of these data are not available on every well, usually for valid economic considerations.

An example of the typical complexity in evaluating well completions is presented in Figure #11. This thermal well had demonstrated the capability of high production rates, but had experienced chronic problems with pump life. Over a 13 month period the pump was replaced 14 times, primarily due to seizing with sand. There were also a number of sand clean outs that showed short term success at increasing production rates. The sand production problem was eventually solved by replacing a damaged wirewrapped sand screen. A careful review of the complete performance parameters also showed a distinct production increase from lowering the pump intake and landing depth. One can also notice that the small steam stimulation in month #4 and the cooling water injection in month #5 did not result in any discernible change in production performance. In this case the negligible effect of these two procedures was because they were not related to the problem. Yet these two procedures can show definite benefits in the correct situation. Many projects have erroneously labeled a particular well completion procedure as unsuccessful, when it has been merely misapplied.

The influence of the reservoir process on well performance should always be considered in any evaluation. It is frequently surprising how direct and immediate the response of production wells is to changes in injection parameters. Response times of several hours to a few days are not uncommon, with pressure changes usually occurring before the related temperature change.

The most effective development of improved well completions involves not only the proper evaluation of evidence, but the correct planning philosophy. A good example comes from the Shell PRISP pilot project where sand production was expected to be a problem. However, there was limited experience available to confirm this view. In response there were three types of sand control techniques employed;

No. of Wells	Technique
16	open hole slotted liners with gravel packs
4	open holes with slotted liners
4	cased and perforated

The open hole slotted liner with a gravel pack was selected for the majority of the wells as it was expected to offer few problems in a pilot operation. Comprehensive records of sand production, well workover type and frequency, and production rates were obtained. Results showed lower than expected sand production for all completions and little discernible difference in production rates between the three completion types. This performance, combined with economic factors resulted in the selection of cased and perforated wells for a commercial scale development. The decision to proceed with a cased and perforated completion was probably made easier by the uneven distribution of well types. The 16 wells with open hole slotted liners gave an excellent basis for comparison. The other two well types could be compared with this basis while only accounting for the unique situations of 8 wells. If 8 wells of each type had been employed, the evaluation may have required the comparison of the unique features of all 24 wells simultaneously, clearly a more difficult task.

7. AREAS OF FUTURE DEVELOPMENT

Well completions for heavy oil have progressed significantly from the initial adoption of conventional oil techniques. Significant improvements remain to be developed.

Casing

Current designs are adequate for most situations, with the exception of regions with formation movement. Tests on concentric casings with a cemented annulus are being conducted in wells with this potential problem. Mathematical formulations of casing - formation movement are being developed.

Coupling designs can still be improved in the areas of leak resistance and make-up consistency. Finite element computer analysis is proving beneficial when applied to this subject.

Cement

Thermal type cements appear to be suitable in most applications. However, verification of long term thermal stability in true field conditions has not yet been established. Further improvements in the setting properties of thermal cements in zones with gas production is required. Investigation of fibre reinforced cements in zones with possible formation movement would also be worthwhile.

Tubing

Current products are very serviceable, therefore only gradual evolutionary changes are foreseen.

Pumps

Under cold production conditions rod fall is still a problem. Helical screw pumps have demonstrated good performance under cold, sandy conditions, but require improvements for high temperatures, high capacities, deep wells and drive train ruggedness.

Pumping wells with high produced fluid temperatures is still very inefficient with pump efficiencies of 15-35% not uncommon. Schemes to cool the pump, remove the flashed vapour or more precisely control vapour locking could prove beneficial. Jet pumps may prove beneficial in both hot and cold wells.

Sand Control

Is the most costly problem for heavy oil wells in terms of well workovers and "lost" production. Recent improvements in sand screen design have included a stainless steel wool filter that offers superior resistance to high velocity abrasion. Methods and application techniques for gravel packing have also improved substantially. The largest problem still remaining is to understand the mechanisms of sand production. Much effort is required in this area.

Bottomhole Instrumentation

The current types of instrumentation provide acceptable results but require improvements to reduce the complexities of installation, allow the use of electrical components in hot environments, and improve self diagnosis.

Other

Many well completion components could benefit form the formulation of a high temperature, elastomer, stable to approximately 400°C.

8. ACKNOWLEDGEMENTS

The permission and encouragement from the Alberta Oil Sands Technology and Research Authority management to present this paper is appreciated. Special thanks is extended to the Operators of the AOSTRA affiliated projects discussed in this paper for the review and suggestions offered and to AOSTRA staff for their assistance.

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- *Performance of Oil Well Cementing Compositions in Geothermal Wells*, Gallers, J.P., Pyle, D.E., 53rd Fall Technical Conference, SPE, Houston, Texas, October 1-3, 1978.
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Figure 1
Heavy Oil Deposits in Alberta

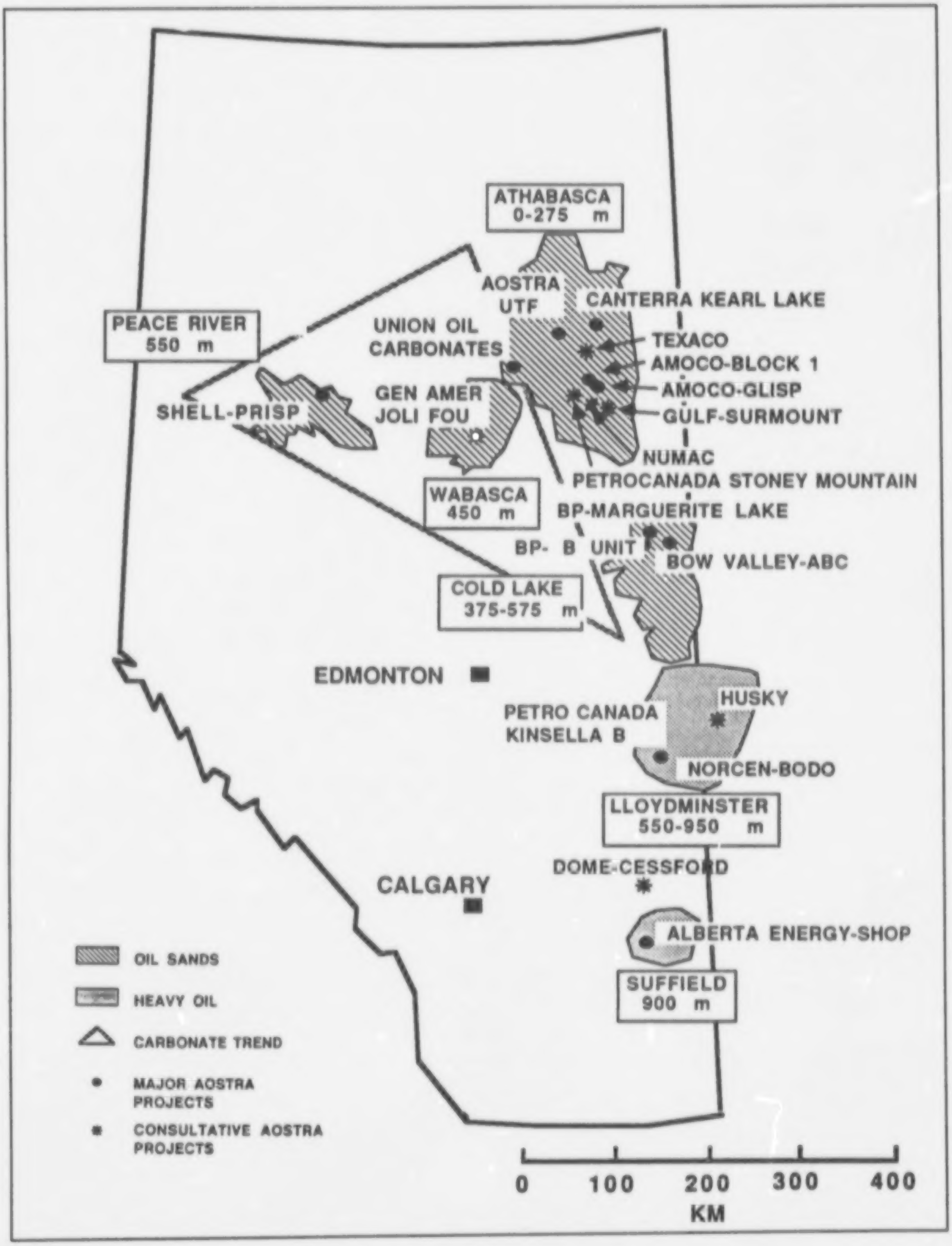

ATHABASCA
0-275 m
AOSTRA
UTF
CANTERRA KEARL LAKE
PEACE RIVER
550 m
UNION OIL
CARBONATES
TEXACO
AMOCO-BLOCK 1
AMOCO-GLISP
GEN AMER
JOLI FOU
SHELL-PRISP
GULF-SURMOUNT
NUMAC
PETROCANADA STONEY MOUNTAIN
WABASCA
450 m
BP-MARGUERITE LAKE
BP- B UNIT
BOW VALLEY-ABC
COLD LAKE
375-575 m
EDMONTON
HUSKY
PETRO CANADA
KINSELLA B
NORCEN-BODO
LLOYDMINSTER
550-950 m
DOME-CESSFORD
CALGARY
ALBERTA ENERGY-SHOP
SUFFIELD
900 m
OIL SANDS
HEAVY OIL
CARBONATE TREND
MAJOR AOSTRA PROJECTS
CONSULTATIVE AOSTRA PROJECTS
0
100
200
300
400
KM

Figure 2
Summary of AOSTRA Heavy Oil Well Types

PROJECT	AREA	FORMATION	RESERVOIR PROCESS	#PROD WELLS	#INJ WELLS
SHELL - PRISP	Peace River	Bullhead	pressure cycle steam drive cyclic steam stimulation	24 3	7 0
AMOCO - BLOCK 1	Athabasca	Mcmurray	quenched combustion	16	24
BP - MARGEURITE LAKE	Cold Lake	Clearwater	cyclic steam stimulation converted to O2 combustion	22	 6
UNION - CARBONATES	Carbonates	Grosmount	cyclic steam stimulation steam drive	9 4	0 1
PETRO CANADA - KINSELLA B	Lloydminster	Wainwright D	cyclic steam stimulation air combustion	5	0
ALBERTA ENERGY - SHOP	Suffield	Upper Mannville J	primary depletion followed by wet air combustion	4	1
CANTERRA - KEARL LAKE	Athabasca	Mcmurray	fracture assisted steam flood	14	8
BOW VALLEY - ABC	Cold Lake	Clearwater	cyclic steam stimulation with CO2 and additives	14	0
AMOCO - GLISP	Athabasca	Mcmurray	fracture assisted steam drive with additives	3	1
NORCEN - BODO	Lloydminster	Mclaren	primary depletion followed by cyclic steam stimulation and steam drive	9	0

Figure 3
Development Process for Well Completion

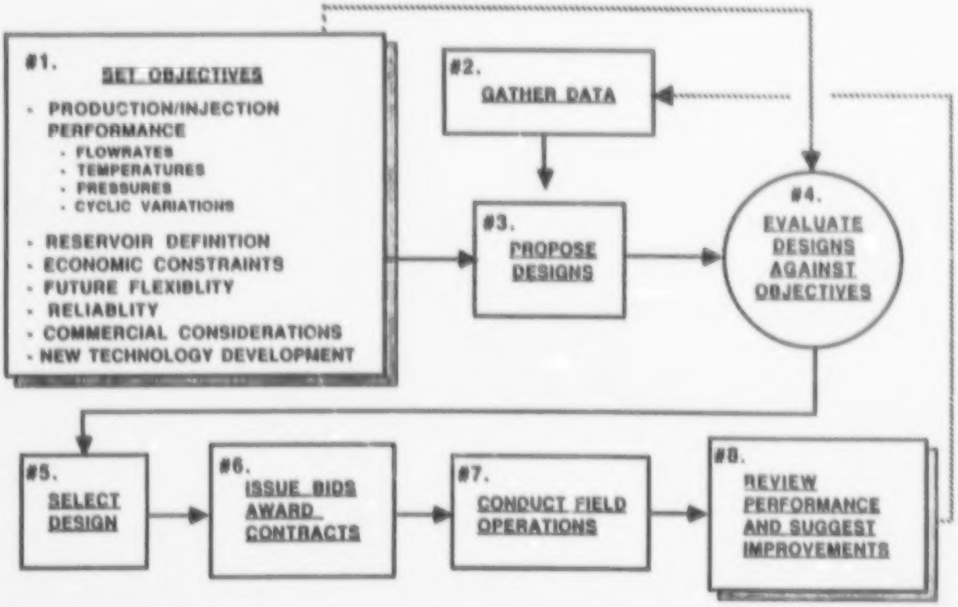

#1. SET OBJECTIVES
- PRODUCTION/INJECTION PERFORMANCE
- FLOWRATES
- TEMPERATURES
- PRESSURES
- CYCLIC VARIATIONS
- RESERVOIR DEFINITION
- ECONOMIC CONSTRAINTS
- FUTURE FLEXIBLITY
- RELIABLITY
- COMMERCIAL CONSIDERATIONS
- NEW TECHNOLOGY DEVELOPMENT
#2. GATHER DATA
#3. PROPOSE DESIGNS
#4. EVALUATE DESIGNS AGAINST OBJECTIVES
#5. SELECT DESIGN
#6. ISSUE BIDS AWARD CONTRACTS
#7. CONDUCT FIELD OPERATIONS
#8. REVIEW PERFORMANCE AND SUGGEST IMPROVEMENTS

Figure 4
Shell PRISP Well Completion

WELL TYPE - PRODUCTION WELL

FIELD - PEACE RIVER

FORMATION - BULLHEAD

RESERVOIR PROCESS - PRESSURE CYCLE STEAM DRIVE

OIL GRAVITY - 9° API

APPROXIMATE DEPTH - 550 m

APPROXIMATE THICKNESS - 25 m

SAND CONTROL - NONE

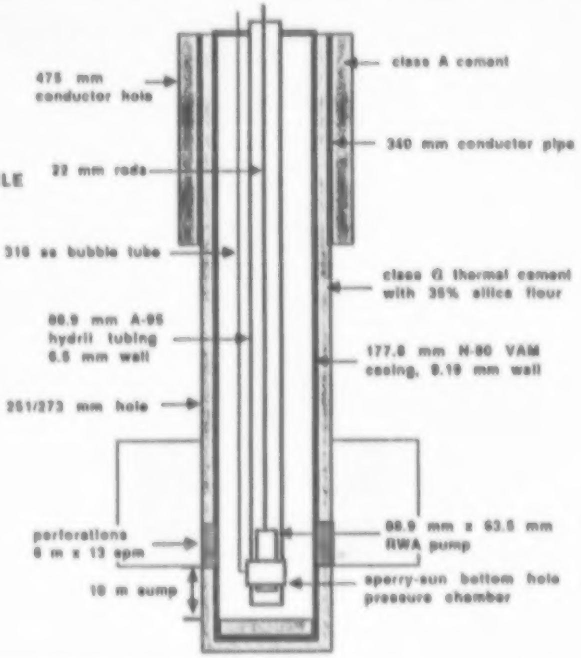

475 mm conductor hole
class A cement
340 mm conductor pipe
22 mm rods
316 ss bubble tube
class G thermal cement with 35% silica flour
88.9 mm A-95 hydril tubing 6.5 mm wall
177.8 mm N-80 VAM casing, 9.19 mm wall
251/273 mm hole
perforations 6 m x 13 spm
88.9 mm x 63.5 mm RWA pump
10 m sump
sperry-sun bottom hole pressure chamber

Figure 5
Shell PRISP Well Completion

WELL TYPE - INJECTION WELL

FIELD - PEACE RIVER

FORMATION - BULLHEAD

RESERVOIR PROCESS - PRESSURE CYCLE STEAM DRIVE

OIL GRAVITY - 9° API

APPROXIMATE DEPTH - 550 m

APPROXIMATE THICKNESS - 25 m

SAND CONTROL - NONE

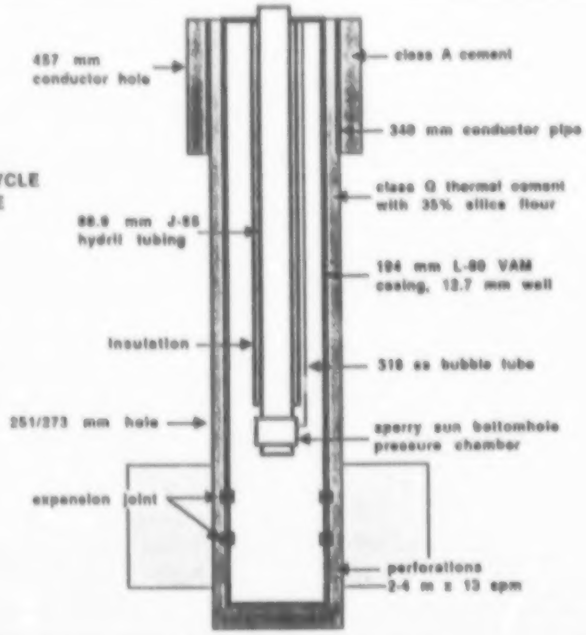

457 mm conductor hole
class A cement
340 mm conductor pipe
class G thermal cement with 35% silica flour
88.9 mm J-55 hydril tubing
194 mm L-80 VAM casing, 12.7 mm wall
insulation
316 ss bubble tube
251/273 mm hole
sperry sun bottomhole pressure chamber
expansion joint
perforations 2-4 m x 13 spm

Figure 6
Bow Valley ABC Project Well Completion

WELL TYPE - PRODUCTION WELL

FIELD - COLD LAKE

FORMATION - CLEARWATER

RESERVOIR PROCESS - CYCLIC STEAM STIMULATION WITH CO2 AND ADDITIVES

OIL GRAVITY - 11° API

APPROXIMATE DEPTH - 450 m TVD

APPROXIMATE THICKNESS - 10 m

SAND CONTROL - NONE

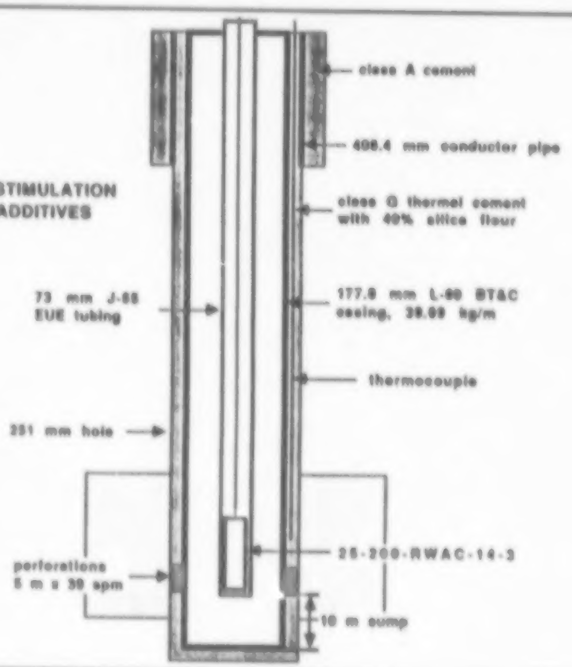

class A cement
406.4 mm conductor pipe
class G thermal cement with 40% silica flour
73 mm J-55 EUE tubing
177.8 mm L-80 BT&C casing, 38.69 kg/m
thermocouple
251 mm hole
25-200-RWAC-14-3
perforations 5 m x 39 spm
10 m sump

Figure 7
Canterra Kearl Lake Project Well Completion

WELL TYPE - PRODUCTION WELL

FIELD - ATHABASCA

FORMATION - MCMURRAY

RESERVOIR PROCESS - FRACTURE ASSISTED STEAM FLOOD

OIL GRAVITY - 7° API

APPROXIMATE DEPTH - 200 m

APPROXIMATE THICKNESS - 50 m

SAND CONTROL - TOP
- WIRE-WRAPPED SCREEN

BOTTOM
- WIRE-WRAPPED SCREEN WITH "SLURRY PACK"

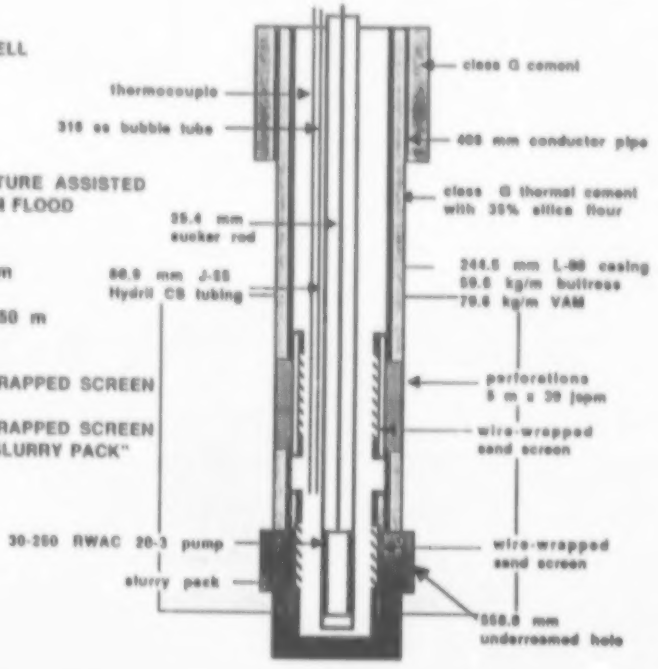

class G cement
thermocouple
316 ss bubble tube
406 mm conductor pipe
class G thermal cement with 35% silica flour
25.4 mm sucker rod
88.9 mm J-55 Hydril CS tubing
244.5 mm L-80 casing 59.6 kg/m buttress 79.6 kg/m VAM
perforations 5 m x 39 jspm
wire-wrapped sand screen
30-250 RWAC 20-3 pump
wire-wrapped sand screen
slurry pack
558.8 mm underreamed hole

Figure 8
Norcen Bodo Project Well Completion

WELL TYPE - PRODUCTION WELL

FIELD - LLOYDMINSTER

FORMATION - MCLAREN

RESERVOIR PROCESS - CYCLIC STEAM STIMULATION

OIL GRAVITY - 12 ° API

APPROXIMATE DEPTH - 700 m

APPROXIMATE THICKNESS - 15 m

SAND CONTROL - WIRE-WRAPPED SCREENS

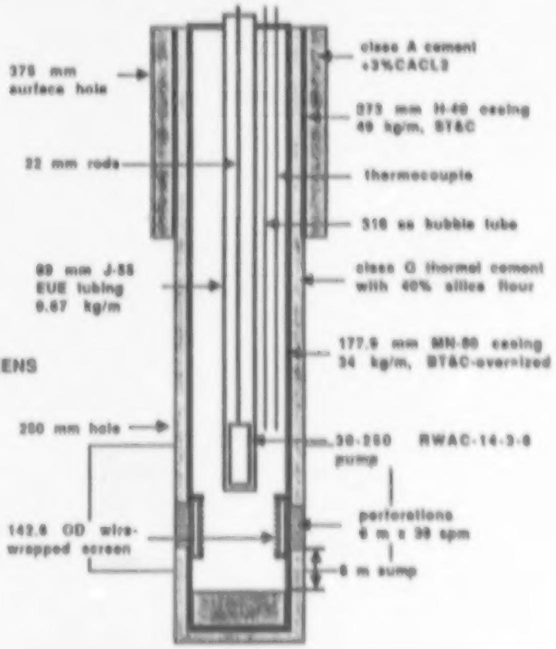

375 mm surface hole
22 mm rods
89 mm J-55 EUE tubing 9.67 kg/m
200 mm hole
142.6 OD wire-wrapped screen
class A cement +3%CACL2
273 mm H-40 casing 49 kg/m, ST&C
thermocouple
316 ss bubble tube
class G thermal cement with 40% silica flour
177.8 mm MN-80 casing 34 kg/m, ST&C-oversized
30-250 RWAC-14-3-6 pump
perforations 6 m x 39 spm
6 m sump

Figure 9
Alberta Energy Shop Project Well Completion

WELL TYPE - PRODUCTION WELL

FIELD - SUFFIELD

FORMATION - UPPER MANNVILLE J

RESERVOIR PROCESS - CYCLIC WET COMBUSTION

OIL GRAVITY - 13 ° API

APPROXIMATE DEPTH - 925 m

APPROXIMATE THICKNESS - 25 m

SAND CONTROL - NONE

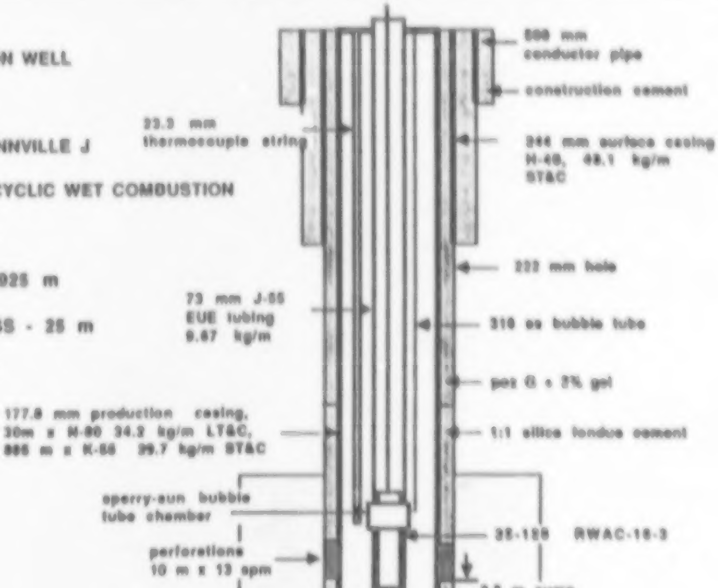

23.3 mm thermocouple string
73 mm J-55 EUE tubing 9.67 kg/m
177.8 mm production casing, 30m x N-80 34.2 kg/m LT&C, 895 m x K-55 29.7 kg/m ST&C
sperry-sun bubble tube chamber
perforations 10 m x 13 spm
508 mm conductor pipe
construction cement
244 mm surface casing H-40, 48.1 kg/m ST&C
222 mm hole
316 ss bubble tube
poz G + 2% gel
1:1 silica fondue cement
25-125 RWAC-16-3
3.5 m sump

Figure 10
Alberta Energy Shop Project Well Completion

WELL TYPE - INJECTION WELL

FIELD - SUFFIELD

FORMATION - UPPER MANNVILLE J

RESERVOIR PROCESS - CYCLIC WET COMBUSTION

OIL GRAVITY - 13° API

APPROXIMATE DEPTH - 925 m

APPROXIMATE THICKNESS - 25 m

SAND CONTROL - NONE

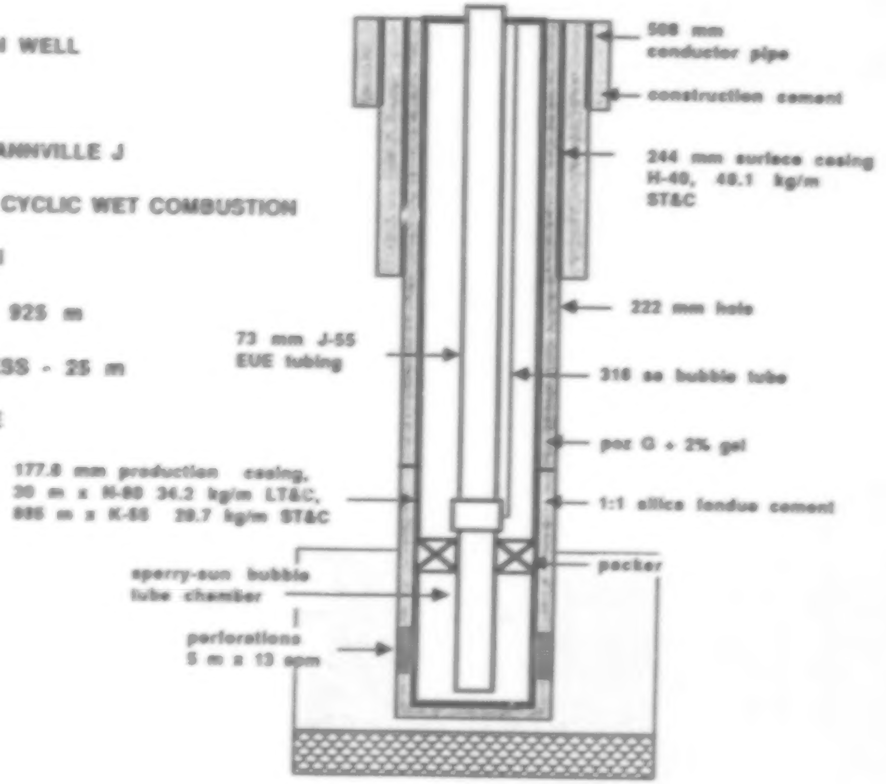
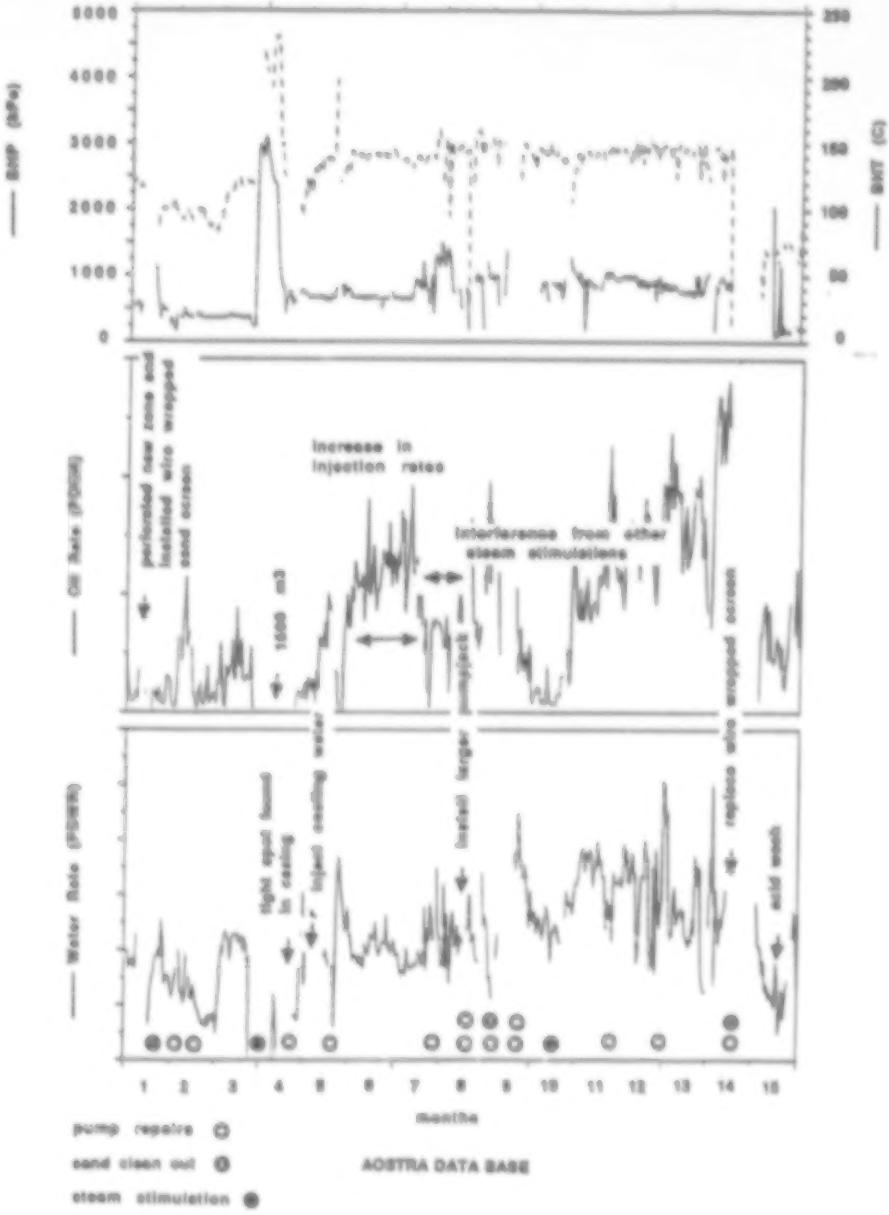

508 mm
conductor pipe
construction cement
244 mm surface casing
H-40, 48.1 kg/m
ST&C
222 mm hole
73 mm J-55
EUE tubing
318 ss bubble tube
poz G + 2% gel
177.8 mm production casing,
30 m x N-80 34.2 kg/m LT&C,
895 m x K-55 29.7 kg/m ST&C
1:1 silica fondue cement
packer
sperry-sun bubble
tube chamber
perforations
5 m x 13 spm

Figure 11
Example Evaluation of Well Performance



5

GEOCHEMISTRY OF CONTINENTAL HEAVY OILS FROM CHINA

Yang Zhiqiong
Gu Xinzhang
Zhang Ling
Research Institute of Petroleum Exploration & Development

ABSTRACT

Based on their geochemistry, three types of heavy oils from China were identified as : (1) those oils containing an abundance of saturated hydrocarbons with evidence of severe biodegradation and where the prophyrins show D_{31} D_{32}*, and* $D_{32} / D_{31} = 0.39$*, (2) those oils containing a moderate amount of saturated hydrocarbons with slight to moderate biodegradation, and the porphyrins show* D_{31} D_{32}*, and* $D_{32} / D31$ *equals 1.38; and (3) those oils containing a very low amount of saturated hydrocarbons with only a slight biodegradation, and where the porphyrins show* $D_{31} / D_{32} = 1.02$*.*

INTRODUCTION

In a recent international symposium on heavy oil and tar sand, the experts agreed on the following definitions: under reservoir conditions, heavy oil is defined as oil whose specific gravity ranges from 0.934 to 1.0 and those viscosity ranges from 100 to 10,000 mPa.s, whereas tar sand is defined to have a specific gravity greater than 1.0 and viscosity greater than 10,000 mPa.s. Heavy oil consists of heavier hydrocarbons (each molecule contains 15 to 20 carbon atoms) than that of light oil. It is more difficult to analyze heavy oils than light oil because of their high specific gravity and viscosity. On the other hand, heavy oil contains high contents of asphaltenes and resin, abundance of polymers, porphyrins, and various trace elements. These properties provide detailed information about heavy oils.

EXPERIMENTS

Heavy oil samples were taken from the Karamay and Ulho fields (three samples) of the Xin-jiang province, Liao-he (four samples), Da-gang (three samples), Sheng-li (one sample) and Jiang-han fields (one sample). Light oil samples were also analyzed in order to compare their properties with those of the heavy oils. All samples were collected from Tertiary formations except that the samples from Xin-jiang which were taken from Jurassic formations. Samples were processed by standard procedures.

The total alkane fraction was obtained from the sediment extracts and from the deasphalted crude oils by silica gel chromatography. After elution of the aromatic fraction with benzene, the resin fraction was obtained by exhaustive elution with methanol. The experimental procedure for obtaining porphyrins has been discussed by Yang et al (1983, 1985).

COMPOSITION OF THE HEAVY OILS

The composition of the four components of the heavy oils from China are listed in Table 1. The average saturated hydrocarbons (50.03%) of the Junggar basin of the Xin-jiang province is higher than that of the Liao-he basin (28.97%) and Sheng-li field (28.26%). The aromatic hydrocarbon percentages are the same for all areas. The percentages of the asphaltene and the resin fractions are high in the Liao-he and the Sheng-li areas. The asphaltene content in the heavy oil studied is higher than that of the normal light oil, but the resin content in the heavy oil is not always higher than that of light oil. Therefore, the quantity of asphaltene, not the resin, is used for heavy oil classification. We shall discuss the four compositions in the following sections.

1. The saturated hydrocarbons have the lowest molecular weight, weakest polarity and lowest specific gravity among the four components. The aromatic hydrocarbons have moderate molecular weight. The resin and asphaltenes have heaviest molecular weight, and the strongest polarity among the four components. The oxygen-sulphur-nitrogen (OSN) compounds of the asphaltene and resin fractions are not simple compounds of al-

cohol, phenol, ketone and aldehyde. The OSN compounds have a specific gravity of 1.0 or higher, and consist of aromatic, heterocyclic and long chain compounds. The ternary plot (Fig. 1) indicates the distributions of the heavy oils studied. The hydrocarbon compositions of oils are controlled by the nature of source rocks, therefore, the oils from the same area should have similar composition. But the composition could be modified by oxidation and biodegradation. Therefore, the composition can also be used to measure the degree of preservation.

2. Steranes and terpanes of the heavy oil were analyzed by gas chromatography - mass spectrometry. The results are displayed in Figure 2. There are three end members displayed in Figure 2, namely: The FQ-2 well of Xin-jiang, the G-753 well of Liao-he, and the G-31 and Y-14-14 wells of Da-gang. The first member was severely biodegraded while the second member was not affected by degradation. The FQ-2 well consists of C_{21}, C_{22}, C_{23} terpanes series. The presence of pentacyclic triterpanes is not obvious, but tricyclic terpanes (C_{19}-C_{26}) are abundant. From Figure 2, demethylated hopane, which is the product of biodegraded-hopane (Connan and Coustau, 1980, Eglinton, 1980), exist in the gas chromatogram. The sample from 9Q-1 well belongs to this type, but was not as severely biodegraded as the sample from the FQ-2 well. The second end member is represented by the samples from G-753 well of Liao-he and W-30 well of the Jiang-han. The steranes, C_{27},C_{28},C_{29}-5α (H),14α (H),17α (H)-20R cholestane are dominant. The relative concentration of the C27 αα R is greater than that of the C27αα S and the C27 ββ S. Terpanes, C30 17α (H),21 β (H)-hopanes are the main components (Fig. 2). The relative concentration of hopanes is as follows: C31, C32 22R 22S, αβ-hopanes ba-moretane (pentacyclic triterpane) (Table 3) tricyclic terpanes and tetracyclic terpanes. The C27-C32 αβ-hopanes are dominated. These phenomena indicate that the steranes and terpanes were preserved after the early diagenesis stage (Connan and Coustau, 1984). The third end member is represented by the samples from G-31 well and Y-14-14 well of Da-gang (Table 3). The G-31 sample show that the percentage of the saturated hydrocarbon is 51.03%, that the aromatic hydrocarbons do not contain porphyrins, that the steranes, C27, C28, C29-20R were changed into C27, C28, C29-20S, that the terpanes, C31 22R was changed into 22S, and that the the αβ-hopanes were changed into βα-moretanes (notes from the interpreter: clarifications are needed to explain the changes from hopanes into moretanes). These phenomena indicate that the samples were moderately biodegraded. Furthermore, all samples except the sample from the G-753 well of Liao-he, contain gammecerane. The content of the gammecerane in the sample from W-30 well of Jiang-han is slightly less than the content of C30 17 α (H)21 β (H)-hopanes. These characteristics indicate that the source rocks of the heavy oil were deposited in a super saline environment.

3. Porphyrins are present in crude oils, source rocks, oil shales and shale, and have a biogenic origin. Porphyrins have been studied and used as a geochemical marker to finger print the oil to its source rock, the maturity level of source rock and the migration path (Baker, 1967; Casagrande, 1976). Research work on porphyrins in China is not very advanced, because the continental sediments contain only small amounts of porphyrins, and because the technology for laboratory analysis has not yet been fully developed. However, porphyrins commonly exist in heavy oils of China.

Thirteen samples were analyzed for the compositions of porphyrins. Three samples from Xin-jiang consist of saturated hydrocarbons (50%). But their aromatic hydrocarbons do not contain porphyrins. The other 10 samples contain nickel porphyrins. The nickel porphyrins have a major peak at 400 nm, and two minor peeks at 516 nm and 554 nm (Fig. 3). Vanadyl porphyrins do not exist in these samples. Table 3 indicates that the samples from Liao-he contain the highest amount of nickel porphyrins, whereas the samples from Jiang-han rank second highest among all samples studied. The amounts of the porphyrins in the samples from Liao-he and Jiang-han indicate that the samples are low mature oil. This finding agrees with the evidence from the study of steranes and terpanes of the saturated hydrocarbon fraction.

The demetallated porphyrins were analyzed by liquid chromatography (HPLC). The etio-porphyrins and DPEP-porphyrins were identified (Figs. 4 and 5). The ratio, DPEP/ETIO varies from 0.96 to 4.65. This ratio can also be used as a measurement for maturity level of oil. As examples, the DPEP/ETIO ratios are 4.17 and 4.65 for the G-753 well and W-30 well, respectively. These high ratios demonstrate that the oils are unaltered (Fig. 6). The heavy oils from Liao-he, Sheng-li, and Da-gang have different oil properties, but they have a similar porphyrin pattern (Fig. 4). This phenomenon suggests that the oil came from the same source rock of the Tertiary Sa-he Group. Samples from Sheng-li, Da-gang, and Jiang-han show that D_{32} D31, and D32 / D31 = 1.38 and indicates that these samples were preserved from the early diagenesis of chlorophyll and are immature oils. The oil from Xin-jiang shows D_{31} D_{32} and the ratio, D_{32} / DD_{31} = 0.39 indicating that oil was demethylated to form the D_{31} peak. Oils from Jiang-han show that the ratio D_{32} / D_{31} equals 1.02. Even though the Jiang-han oil is immature, it occurred under a reducing environment which accelerated the transformation of D_{32} into D_{31}.

4. Resins and asphaltenes were analyzed by infra red spectroscopy. Four peak areas (1740, 1720-1700, 1600, 720 cm^{-1}) in the infra red spectrum can be used to identify basic carbon structure and to obtain information about the oxide content. The results of the infra red analysis are displayed in Figures 7 and 8. Figure 7 shows that the resins absorb radiation in the region 1700 cm^{-1} and 1300-1000 cm^{-1}. The spectra of the resins in the heavy oil from Xin-jiang show characteristic absorption bands of C = 0 stretching of the carbonyl at 1730 cm^{-1} and conjugated with -O- at 1275 cm-1, 1120 cm^{-1}, and 1070 cm^{-1}. This molecular structure may belong to saturated fatty ether. This explanation of the structure agrees with the fact that the Xin-jiang sample contains an abundance of CH_3 and CH_2. The heavy oils from Sheng-li and Da-gang show characteristic absorption bands of C = 0 at 1690 cm^{-1}, and may belong to the aldehyde, ketone, acid and aromatic fat groups. The heavy oil of the Jiang-han shows the absorption band of C = 0 at 1650 cm^{-1}, and may belong to a compound such as alkene alcohols -ketol ether, m-oxophenyl and quinoid forms. In most cases, the asphaltenes show characteristic absorption bands at 1630-1650 cm^{-1} with exceptions at 1700 cm^{-1} and 1600 cm-1, which are very similar to that of coal.

5. The quantities of the trace metallic elements in heavy oil ashes are displayed in Table 4. Take the sample from Jianghan as an example, the heavy oil ashes contain Co, Ca, Si, Fe, Ge, Zr, Mg, Mo, Pb, Cr, Ti, Ni, and V. The quantities of the trace metallic elements (except Ca, Mg, and Pb) are 1 to 20 times greater than that of the heavy oil occurring below. The element, Ge, exists only in the Qian-1 member. From Table 4, we can observe that the specific gravity, viscosity and sulphur content and trace metallic elements are related. For example, in the case of the Qian-1 member, the specific gravity, viscosity, sulphur content, number of metallic trace elements and their amounts decrease with increasing depth. This indicates that the quantity of the trace metallic elements may be used for classification of heavy oils. For example, the quantity of V+Ni may be used as criteria for classification (Table 2). From Table 5, the quantities of nickel and vanadyl are low, and the ratio, V/Ni, is several tens or several hundred times lower than that of heavy oil of marine origin.

CONCLUSIONS

From the analysis, three types of oils are identified as follows:

- *1. Heavy oil from Xin-jiang contain abundant saturated hydrocarbons. The resin is dominated by saturated long chain ether and unstable αβ -ether. Porphyrins show D_{31} >D_{32}, and D_{32} / D_{31} = 0.39. The steranes and terpanes show biodegradation.*

- *2. The heavy oil from Sheng-li, Liao-he, and Da-gang contain a moderate amount of saturated hydrocarbons. Heavy oil from Sheng-li and Da-gang contain resin which is dominated by aldelhyde, ketone, acid and aromatic fat. Porphyrins show D_{31} <D_{32}, D_{32} / D_{31} equals 1.38. Heavy oil from Da-gang was moderately biodegraded while the heavy oil from Liao-he has been slightly biodegraded.*

- *3. The heavy oil from Jiang-han contains a very low amount of saturated hydrocarbons. Resin is dominated by the quinoid form. Porphyrins show D_{31} / D_{32} = 1.02. The oil has slightly biodegraded.*

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Table 1
Compositions of the Heavy Oils from China

Region/Field	Well	Depth(m)	Age	Specific Gravity	Viscosity (@ 20 °C)	Composition (%)							
						Saturated		Aromatic		Resin		Asphaltenes	
Xin-Jiang													
Ulho	FQ-2		J_3			44.66	50.03*	22.33	20.66*	29.49	26.58*	6.15	6.48*
	C-1	243.5-254.0	J_3	0.9558	162752.63	43.84		21.92		34.23		6.13	
Karamay	9Q-1		J_3	0.9212	926.31 (@ 30 °C)	64.24		18.35		16.04		5.70	
	9Q-25	276.5-270.5	J_3	0.9339		61.60		17.72		16.03		7.17	
Dagan													
Yangsanmu	Y-14-14		N_m	0.9349 (@ 74 °C)	1200	40.41	45.19	28.08	26.51	22.60	23.[illegible]	8.22	6.09
	Y-5-11	1232.8-1309.0	N_m	0.9634	1197.19	44.09		25.07		26.80		4.90	
Zaoyuan	Z-1219	2065.6-2093.2	E_k	0.9006	261.69	49.55		17.12		26.32		2.70	
Gaoshangbao	G-31	1836.6-1845.0	N_m	0.9412	139.45	51.06		26.37		21.58		5.14	
Liao-he													
Gaosheng	G-753	1594.0-1642.0	E_s	0.9311 (@ 46 °C)		38.83	28.97	20.71	21.44	35.92	44.01	11.33	9.02
Shuguang	S-1-36-333		E_s		18088	29.17		28.13		42.01		7.64	
Huanxiling	J-7-32-30	942.2-978	E_s	0.9870	92.1 (@ 100 °C)	27.16		20.58		41.15		11.11	
	J-8-13-43	1170.2-1128.0	E_s	0.9686	1000 (@ 50 °C)	20.72		16.33		56.97		5.98	
	H-2-14-16	1754.6-1854.4	E_s	0.8559	4.81 (@ 50 °C	52.31		13.89		30.10		3.70	
Shengli													
Shangjiesi	S-2-1			0.9692 (58 °C)	15000	28.26	28.26	24.84	24.84	22.98	22.98	12.11	12.11
Jianghan													
Wangchaun	W-30	1201.0-1218.8	E_q^1	0.9635	251.9	16.57	16.57	33.44	33.44	35.43	35.43	15.50	15.56
	W-7-2	1318.6-1426.0	E_q^1	0.8701	1736.0 (@ 50 °C)	42.60		29.08		31.89		2.88	

* Average of the saturated, aromatic, resin and asphaltenes of the heavy oil only, i.e. samples with specific gravity less than 0.9300 were excluded from the calculated of the average.

Table 2
Classification Schemes for Heavy Oils from China

Type	Specific gravity	Viscosity (@ 37.8 °C)	Viscosity (@ 100 °C)	200 °C component vol. %	Components Asphaltene weight	Metal (V+Ni)ppm	Tar %
Normal crude	0.769 - 0.903	1.5 - 50	7.6	10 - 70	0.3	< 10 - 60	<1 - 6
Medium gravity crude	0.904 - 0.934	40 - 400	6.7 - 2.3	3 - 20	<1 - 5	10 - 20	5 - 11
Heavy crude I	0.935 - 0.965	100 - 1200	11.5 - 42	0 - 10	2 - 7	120 - 26	5 - 12
Heavy crude II	0.966 - 0.993	800 - 1500	32 - 47	0 - 6	6 - 15	180 - 55	5 - 12
Heavy crude III	0.994 - 1.040	1300 - 15000 or more	44 - 170 or more	0 - 4	7 - 27	210 - 13	10 - 12

Table 3
Compositions Of The Resin, Asphaltenes, Steranes, Terpanes And Porphyrins

Region/Well	Resins cm⁻¹				Asphaltene (absorbance/mg)						Porphyrins		Steranes				Terpanes		
	1700/1460	1700/1600	750/720	1600/1460	2920 cm⁻¹	1637 cm⁻¹	1380 cm⁻¹	880 cm⁻¹	810 cm⁻¹	750 cm⁻¹	Content	DPEP/ETIO	1	2	3	4	5	6	7
Xin-jiang																			
FQ-1	1.5	6.17	3.57	0.24	1.097	0.03	0.128	0.041	0.041	0.03	36.31	3.91						7.06	0.86
C-1	1.56	3.3	3.81	0.29	0.853	0.007	0.135	0.023	0.038	0.025	34.15	1.68							
9Q-1	1.68	5.04	3.26	0.33							Trace		1.86	0.65	0.91	1.16	0.32	0.97	0.1
9Q-25	0.96	3.91	0.38	0.24	1.160	0.05	0.12	0.06	0.03	0.03	Trace								
Da-gag																			
Y-14-14	0.43	1.43	0.67	0.3	1.363	0.045	0.099	0.041	0.04	0.039	69.10	2.66	1.20	1.25	1.5	1.06	0.31	0.12	0.11
Y-5-11	0.39	1.76	0.89	0.33	0.863	0.066	0.049	0.028	0.034	0.034	30.06	2.01							
Z-1219	0.39	1.17	0.45	0.33							65.22	0.96	1.80	1.71	1.65	1.40	0.3	0.06	0.06
C-31	0.56	1.26	0.93	0.44	0.076		0.067	0.029	0.036	0.037	Trace		1.1	0.88	1.01	1.22	0.39	0.11	0.10
Liao-he																			
G-753	0.87	2.55	1.55	0.32	0.455	0.067	0.088	0.19	0.19	0.19	211.35	4.17	2.33	1.37	2.12	0.53	0.23	0.21	0.17
S-1-36-333	1.37	4.92	3.0	0.32	0.833	0.017	0.064	0.042	0.042	0.036	155.35	1.66							
Sheng-li																			
S-2-1	0.64	2.07	0.83	0.31	1.052	0.036	0.059	0.025	0.031	0.033	92.92	2.40							
Jiang-han																			
W-30	0.38	1.86	0.77	0.21	0.776	0.075	0.058	0.02	0.023	0.023	141.52	4.65	1.89	1.27	2.12	0.88	0.20	0.22	0.18
W-7-2	0.32	1.2	0.5	0.27	1.093	0.058	0.075	0.021	0.021	0.021	103.30	2.57							

1. C_{27} $\alpha\alpha$R / C_{27} $\alpha\alpha$S
2. C_{29} $\alpha\alpha$R / C_{29} $\alpha\alpha$S
3. (C_{27} + C_{28} + C_{29}) 20 R / (C_{27} + C_{28} + C_{29}) 20S
4. C_{31} 22 S / C_{31} 22 R
5. $\beta\alpha$ - moretane / $\alpha\beta$ - hopane
6. Tricyclic terpanes / Pentacyclic terpanes
7. Tricyclic terpanes / Total terpanes

Table 4
Properties of the Trace Metallic Elements of Heavy Oils in the Junggar Basin

Well	Formation	Viscosity @ 20 °C	Specific gravity D_4^{20}	Sulphur %	Trace metallic element (ppm) Co	Bi	Fe	Ge	Zr
W-1-31-11	Qian-1	63	0.9196	5.26	1.24	8.50	>15.44	<0.19	0.39
W-1-31-13	"	356	0.9569	10.39	2.32	8.60	8.23	<0.19	<0.37
W-1-32-8	"	340	0.9604	8.60	1.84	>21.24	>14.16	0.23	0.38
W-1-31-7	"	276	0.9662	7.43	2.53	8.27	15.76	<0.20	0.43
W-1-33-8	"	297	0.9791	8.92	5.52	>23.31	>15.54	0.30	0.51
W-1-35-10	"	265	0.9792	10.03	>7.37	21.74	>14.74	0.20	0.40
W-1-33-11	"	270	0.9801	10.32	8.0	9.60	>16.00	0.21	0.42
Z-71	Qian-2	16.0	0.8728	1.78	0.41	10.72	5.52	trace	<0.38
Z-45	"	18.12	0.8734	1.88	0.47	14.58	3.78	trace	<0.39
Z-4-10	"	-	-	-	-	>5.37	>3.58	trace	0.16
W-42	Qian-3	12.7	0.8618	0.97	-	4.52	2.42	-	-
W-10-3	"	13.1	0.8620	-	-	8.30	8.76	-	<0.19
W-27	"	13.64	0.8664	1.43	-	12.72	3.74	-	-
W-44	"	17.2	0.8743	1.02	-	5.15	3.34	-	-
WZ-12-6	Qian-4	7.64	0.8442	0.15	-	5.40	2.61	-	-
WZ-10-6	"	8.4	0.8459	0.29	-	3.35	1.34	-	-
WZ-14-8	"	7.68	0.8473	0.3	-	4.60	2.20	-	-
WZ-12-3	"	10.3	0.8502	0.55	-	5.49	3.66	-	-
L-40	Xin-1	4.3	0.8180	0.09	-	5.88	3.92	-	-
L-2	"	4.3	0.8234	0.18	-	5.7	0.19	-	-
L-23	"	6.5	0.8306	0.12	-	0.48	0.42	-	-
L-30	"	9	0.8321	0.05	-	4.70	0.12	-	-

Well	Formation	Trace metallic element (ppm) Mg	Mo	Cr	Ni	Ti	Ca	V	Pb
W-1-31-11	Qian-1	<1.16	7.11	0.33	>15.46	4.95	5.26	2.01	trace
W-1-31-13	"	<1.12	>14.96	0.37	14.21	0.25	2.32	3.44	trace
W-1-32-8	"	<1.06	6.37	0.23	>14.16	3.68	2.83	1.91	trace
W-1-31-7	"	<1.18	6.15	0.49	>15.76	2.21	4.89	>2.36	trace
W-1-33-8	"	1.17	>7.77	0.37	>15.54	>7.77	9.71	>2.36	trace
W-1-35-10	"	<1.11	>7.37	0.43	>14.74	5.16	5.01	>2.21	trace
W-1-33-11	"	<1.20	>8.0	0.66	>16	>8.0	2.64	>2.40	trace
Z-71	Qian-2	3.91	0.57	0.11	16.09	12.64	29.87	1.07	trace
Z-45	"	1.18	0.67	0.12	17.38	15.76	5.52	1.47	trace
Z-4-10	"	0.34	<0.09	0.01	3.58	0.21	2.69	0.54	0.02
W-42	Qian-3	2.57	<0.39	trace	10.53	<0.39	5.46	2.18	trace
W-10-3	"	<0.56	<0.19	0.03	15.24	0.35	2.36	0.95	0.08
W-27	"	<1.12	trace	trace	14.96	0.39	3.74	0.56	trace
W-44	"	<1.14	trace	trace	15.16	0.36	3.63	0.83	trace
WZ-12-6	Qian-4	0.27	-	-	2.34	0.09	0.67	0.28	trace
WZ-10-6	"	0.43	-	0.01	2.70	0.09	0.60	0.26	<0.01
WZ-14-8	"	0.32	-	-	2.70	0.10	0.94	0.21	<0.02
WZ-12-3	"	1.24	0.09	0.03	3.66	0.81	5.49	0.55	0.27
L-40	Xin-1	>5.88	-	-	0.71	0.22	5.88	0.09	-
L-2	"	0.82	-	-	0.21	0.10	0.29	0.03	-
L-23	"	>6.0	-	-	3.10	<0.18	>6.0	0.04	-
L-30	"	0.32	-	-	<0.17	-	<0.26	<0.03	-

Table 5
The V and Ni Contents of the Continental Heavy Oils from China and Marine Heavy Oils from Other Countries

Region	Gravity D^{420}	Trace metallic ppm V	Ni	V/Ni
2	0.9212	0.01	0.25	0.04
	0.9339	0.3	11	0.027
5	0.9311	3.0	108	0.028
7	0.92-1.0033	1.6	88	0.018
10	0.9692(58 ℃)	1.7	36	0.047
3	0.9349(74 ℃)	0.76	27	0.028
		0.94	19	19
11	0.9635	2.38	>16	<0.15
Venezuela (Lagomedio)		133	13	10.230
Kuwait		31	9.6	3.225
USSR (Romashigin)		53.7	21.5	2.381

Figure 1
The Components of the Heavy Oils from China. 1: Xin-jiang; 2: Da-gang; 3:Sheng-li; 4: Liao-he; 5: Jiang-han

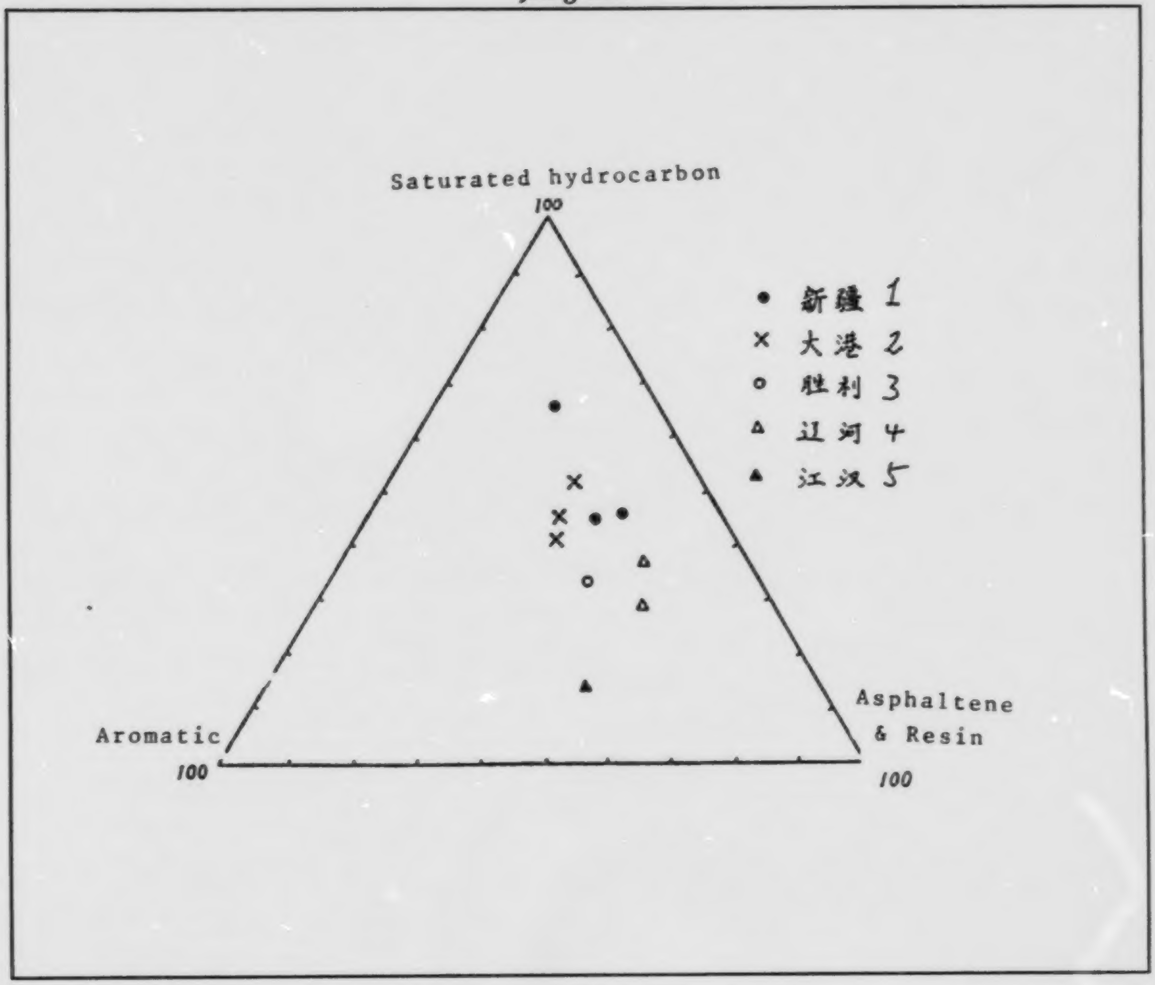


Figure 2
Mass Chromatograms of the Saturated Hydrocarbons, Steranes and Terpanes of the Heavy Oil from China

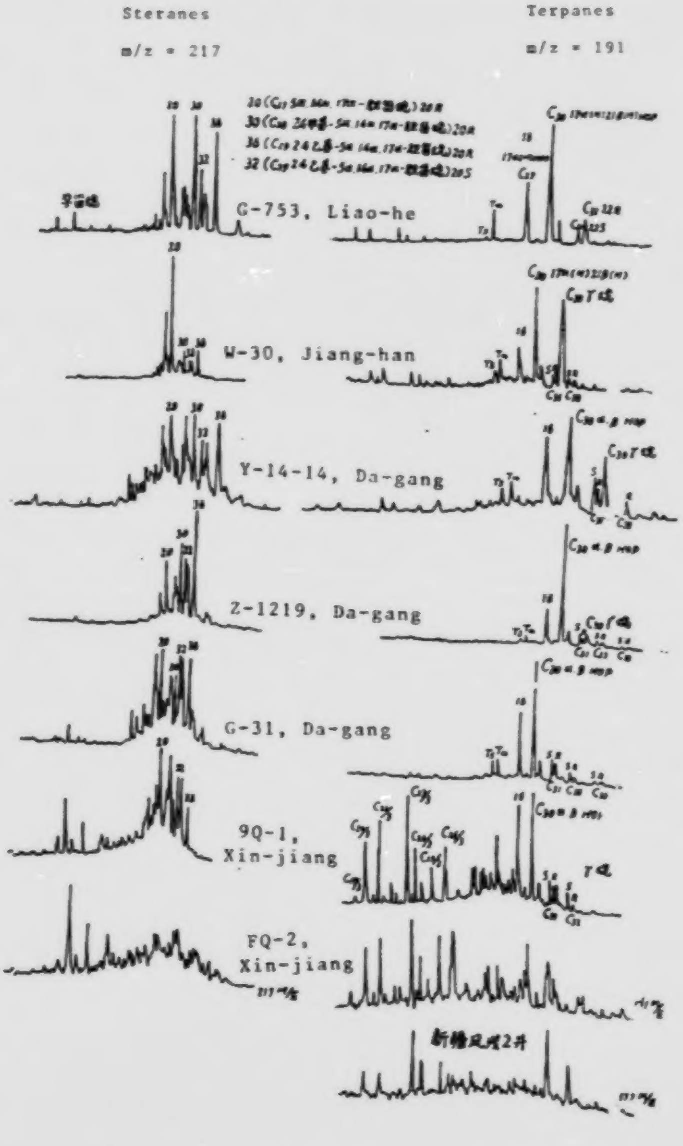


Figure 3
The Absorption Spectrum of the Nickel Porphyrins of the Heavy Oils. 1: S-2-1, Sheng-li; 2: FQ-2, Xin-jiang; 3. 8-1-36-33, Liao-he; 5. W-30, Jiang-han; 6. Y-14-14, Da-gang

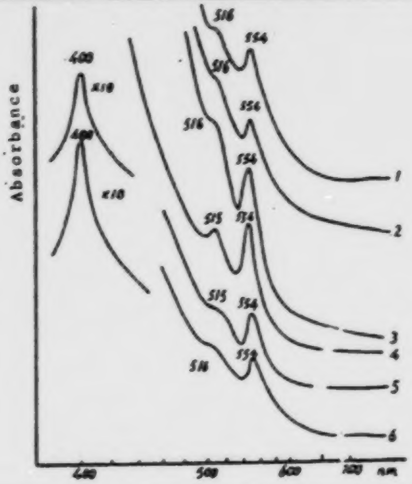


Figure 4
HPLC Spectrum of the Porphyrins from the Heavy Oils. 1: S-2-1, Sheng-li; 2: W-7-2, Jiang-han; 3: C-1, Xin-jiang; 4: FQ-2, Xin-jianf; 5: S-1-36-333; 6: G-753, Liao-he; 7: Y-14-14, Da-gang; 8: Y-5-11, Da-gang

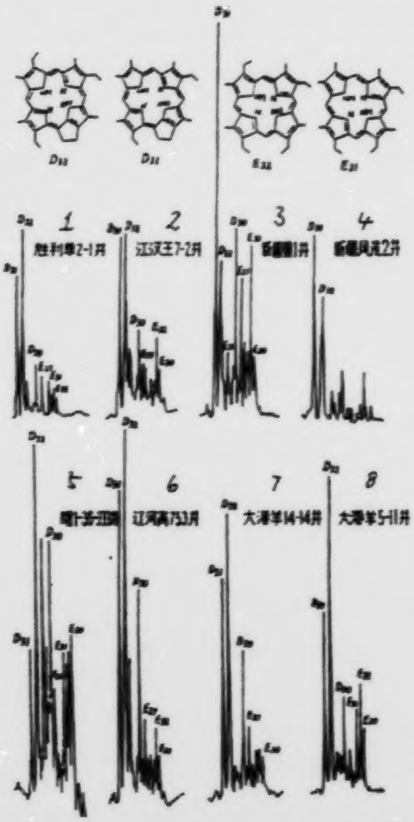


Figure 5
Mass Spectrum of the Porphyrins from Well G-753

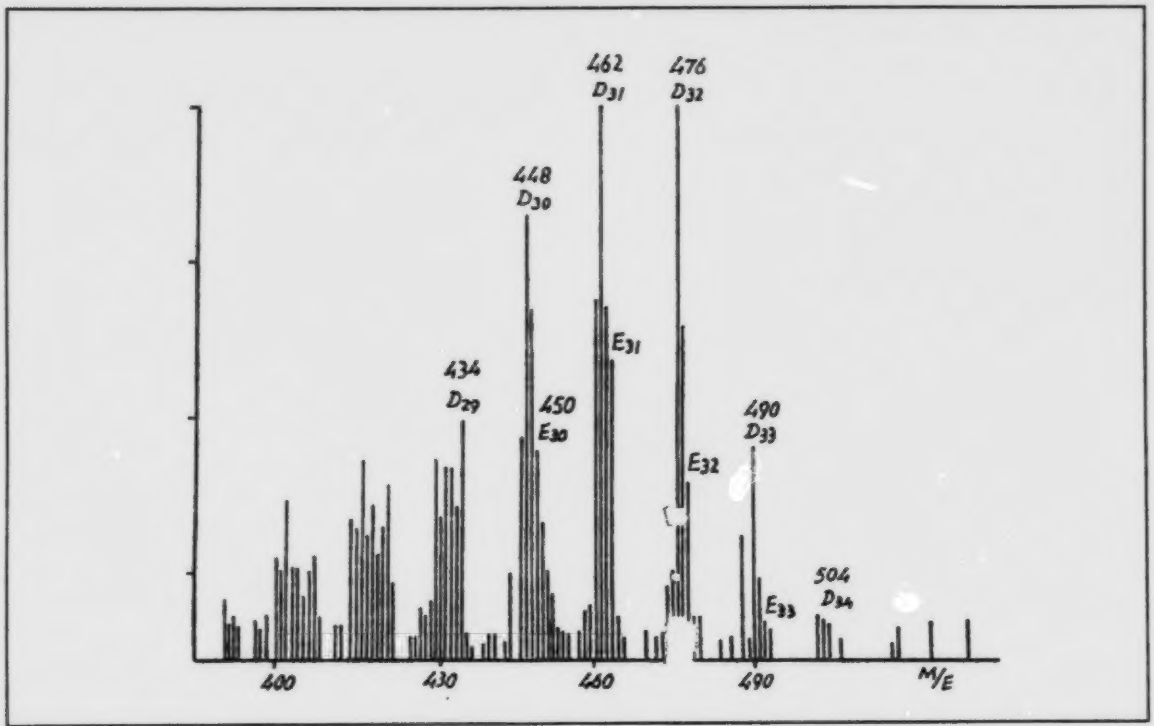


Figure 6
Cross Plot form the Porphyrins vs DPEP/ETIO. 1: FQ-2, Xin-jiang; 2: W-30, Jiang-han; 3: G-753, Liao-he; 4: Y-14-14, Da-gang; 5: W-7-2, Jiang-han; 6: S-2-1, Sheng-li; 7: Y-5-11, Da-gang; 8: C-1, Xin-jiang; 9: Shu-guang, Liao-he; 10: Z-1219, Da-gang; 11: G-31, Da-gang; 12: 9Q-1, 9Q-7, Xin Jiang

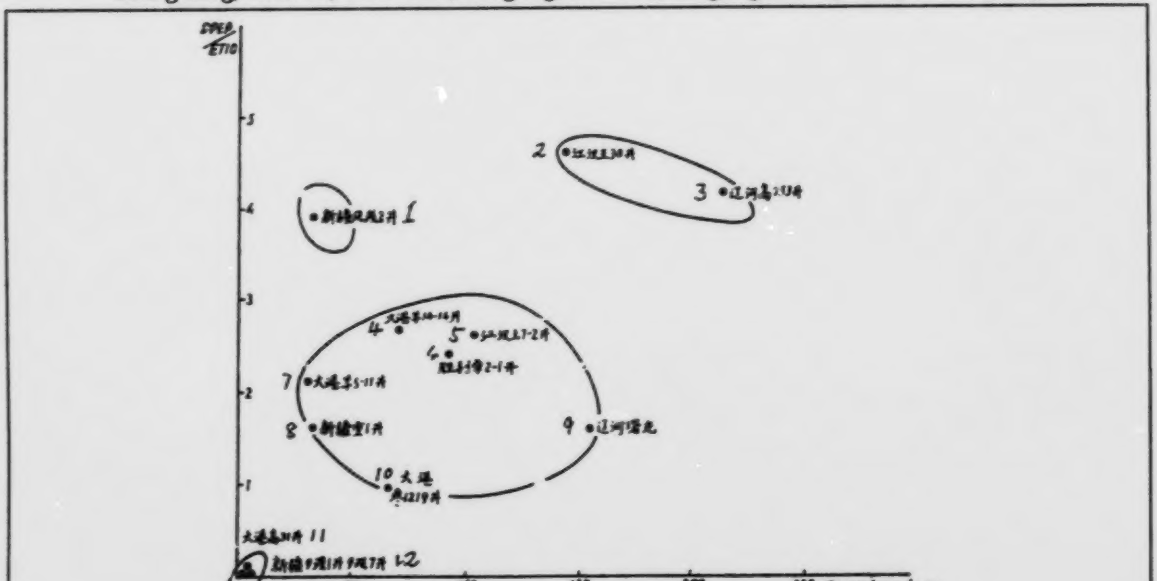


Figure 7

Infrared Spectrum of the Resin from the Heavy Oils. 1: FQ-2, Xin-jiang; 2: C-1, Xin-jiang; 3: 9Q-1, Xin-jiang; 4: S-1_36-333, Liao-he; 5: G-753, Liao-he; 6: S-2-1, Sheng-li; 7: Y-14-14, Da-gang; 8. Y-5-11, Da-gang; 9. Z-1219, Da-gang; 10. W-30, Jiang-han; 11. W-7-2, Jiang-han

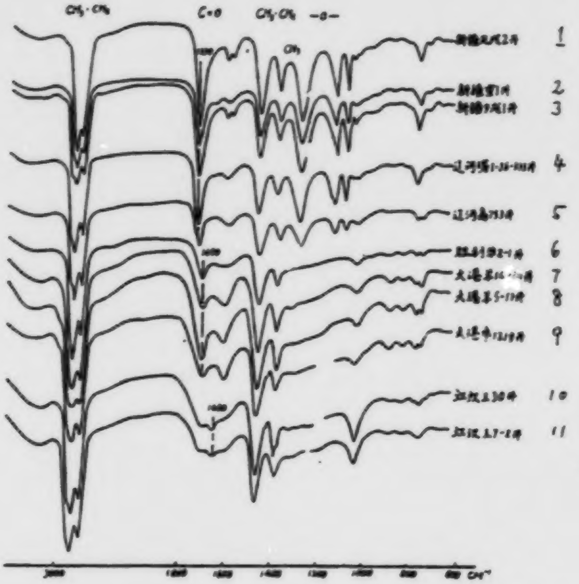
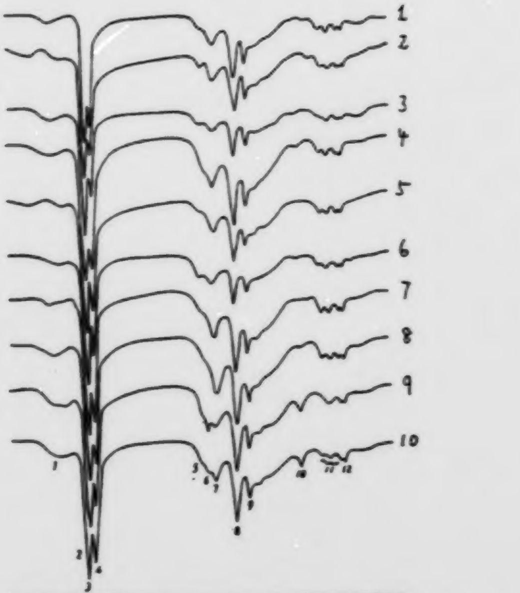


Figure 8

Infra Red Spectrum of the Asphaltenes of the Heavy Oils. 1: FQ-2, Xin-jiang; 2: C-1, Xin-jiang; 3: 9Q-25, Xin-jiang; 4: G-753, Liao-he; 5: S-1-36-333, Liao-he; 6: Y-5-11, Da-gang; 7: Y-14-14, Da-gang; 8: S-2-1, Sheng-li; 9: W-30, Jiang-li; 10: W-7-2, Jiang-han



6

GEOLOGY AND THE ORIGINS OF HEAVY OIL FROM THE NORTHWESTERN JUNGGAR BASIN

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Guo Hongpo

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ABSTRACT

The objective of this paper is to discuss the origin of the heavy oil in the northwestern Junggar basin based on the geological setting and the geochemical characteristics. The heavy oil belt of the northwestern Junggar basin extends about 150 km long and is distributed into several shallow horizons. The oil has a high resin content, acidity, and viscosity, but low wax, sulphur, pour point and asphalt contents. Geochemical evidence suggests that the heavy oil was mainly formed by biodegradation.

INTRODUCTION

The Junggar basin located in the northwestern region of China, is an intermontane basin surrounded by the Altay mountains to the northeast, the Junggar mountains to the northwest, and the Tianshan mountains to the south (Fig. 1). The basin area is about 130,000 km^2 with a maximum sedimentary thickness of 14,000 m. The Junggar basin is very rich in petroleum resources including heavy oil.

A large scale exploration program began in 1949 resulting in the recognition of the Karamay - Xie-zi-jie petroleum play. The Karamay oil field is a representative member of this play which is characterized by a large amount of tar sand outcrop at the surface, natural asphalt veins and heavy oil reservoirs at shallow depths.

There are two theories of the origin of heavy oils: primary and secondary origins. The primary origin is the accumulation of immature crude oils, whereas the secondary origin is the result of degradation of crude oils due to oxidation, flushing by water, or biodegradation. The secondary origin can also be a result of long distance migration. This paper attempts to integrate the geological and geochemical information for the heavy oil from this play and to delineate the possible hypothesis for the origins of the heavy oil. The result of this study will provide vital information for future exploration.

GEOLOGY

■ Tectonics and Sedimentations.

The Junggar basin is an intermontane and multi-cycle basin. Its tectonic history can be divided into four stages.

(1) Early Hercynian stage. The basin began to develop on a crystalline shield. According to the magnetic data, the depth of the crystalline basement is about 17,000 to 18,000 m. The basin began with a shelf sedimentation at the central shield surrounded by geosynclines.

(2) Late Hercynian stage. During this stage, the Early Permian sediments were deposited at the fault depressions with large amounts of volcanic rocks. The sediments deposited have a thickness of 2000 to 4000 m. This sequence contains mature to over-mature source beds which are the best source rocks in the basin (Table 1).

At Late Permian time, the basin was an inland basin with many local depocentres. In the southern portion of the basin, the sediments consist of oil shale and dolomite with a thickness of 2000 to 4500 m. In the eastern and central parts of the basin, the sediments are dark grey lacustrine deposits with a thickness of 1000 to 2000 m, and with a thickness of 2000 m to 4500 m in the northwestern part of the basin. At the edge of the basin, alluvial-fluvial deposits are found which are favorable for reservoirs development (Table 2).

(3) Indo-China-Yanshan stage. During this stage the basin was transformed into a shallow inland lake. The Early and Middle Triassic fluvial and lacustrine sediments make good reservoirs (Table

2). Although in the northwestern portion of the basin source rock quality is poor (Table 1), but these rocks act as an excellent cap rock at the northwestern basin.

At the end of Triassic time, a series of northeast overthrusts was formed as the result of the Indo-China-Yanshan tectonic movement which produced most of the traps in the basin. Major migration events occurred at this stage. During the Jurassic time period, the depocentre shifted towards the south. The Early Jurassic sediments were deposited in lacustrine or braided stream environments. These sediments constitute only minor reservoirs and source rocks (Table 2). The Late Jurassic fluvial sediments are the major reservoirs for the heavy oil. At the end of this stage, the Yanshan movement destroyed some of the original traps but produced new traps.

During the Cretaceous time, the basin developed into a simple depression with the depocentre in the southern part of the basin. Sediment thickness of 3500 m are recorded at this depocentre. At this time major migration events ceased. Cretaceous rocks have poor reservoir qualities.

(4) Himalayan stage. During this stage, the basin was uplifted. Tertiary fluvial sediments were deposited reaching thickness of about 1000 to 1500 m. The fluvial sediments form traps (Table 1), but the source rocks are not mature.

OCCURRENCES OF THE OILS IN THE NORTHWESTERN BASIN

The main tectonic feature at the northwestern end of the basin is a large scale overthrust belt trending NE-SW extending for about 250 km long and that shows movement of about 9 to 25 km to the southeast. The stratigraphic thickness of the hanging and downthrow walls are very different. The overthrust belt and its vicinity can be divided into five zones according to their structural styles: (1) The main body of the overthrust belt (this belt consists of nappe structures) which consists mainly of Carboniferous (C_1) and Permian basement rocks (Figs. 2 and 3); (2) The front faulted zone located in front of the main overthrust body where the rocks consist of Carboniferous basement rock, and lower Permian (P_{1J}, P_{1F}), Triassic and Jurassic sediments; (3) The downthrow wall consisting of Permian, Triassic and Jurassic sediments which form monoclinal structures; (4) Sediments of Lower Jurassic (J_1), Upper Jurassic(J_3) and Lower Cretaceous (K_1) laid onlap over the main overthrust body and showing pinch out features; (5) The outer front of the overthrust which was folded into gentle anticlines or monoclines.

The main overthrust body is located immediately to the northwest of the main source rocks in the basin. Numerous faults and unconformities served as excellent channels for oil migration and accumulation (Figs. 4, 5). At the present time, four trap types are recognized in the northwestern portion of the basin: (1) Monoclines in the downthrow wall. Blocks 5 and 8 of the Karamay oil field and Bai-kou-quan oil field are the examples of this trap type; (2) Traps in the front faulted zone. Blocks 1, 2, and 7 of the Karamay oil field are the examples; (3) Anticlinal traps distributed in the outer front of the overthrust belt such as the Feng-cheng-cheng and the Xie-zi-jie anticlines; (4) Unconformity traps which can be further subdivided into two trap types. The first type occurs below the unconformity surface and is distributed in the main body of the overthrust and the front faulted zone where fracture reservoirs were formed in the crystalline basement rocks. Blocks 1 (Carboniferous), 7 (Lower Permian) and 9 (Carboniferous) of the Karamay oil field are examples of this type. The second trap type are pinch out traps occurring at the surfaces of unconformities. The Qi-gu Group ($^1J_3$) and the Tu-gu-lu Group (K_1) of the Feng-cheng-cheng anticline and blocks 6 and 9 of the Karamay oil field are examples of this type. Most of these reservoirs produce heavy oil.

RESERVOIR CHARACTERISTICS AND TRAP TYPES

Reservoir Characteristics.

The heavy oil reservoirs occur in the main body of the overthrust belt and the onlap zone above the main body. The characteristics are summarized in the following sections.

The heavy oil belt extends about 150 km in length, usually at a depth of between 200 to 600 m, and occasionally between 1100 to 1400 m. The heavy oil distributes stratigraphically in the crystalline basement (C_1) of the main overthrust belt, Middle Triassic ($^1T_2$), Lower Jurassic ($^1J_1$), Upper Jurassic(J_3), and Lower Cretaceous (K_1). The Lower Jurassic reservoirs constitute the major heavy oil resource of the basin. Sedimentation model for the Lower Jurassic is a fluvial environment. Net pay ranges from 8 to 15 m. The sediments are well sorted, medium- to fine-grained, friable sandstones with a clay content ranging from 6 to 8%. Porosity ranges from 25 to 30%, permeability ranges from 0.3 to 0.5 mm^2. The reservoirs possess a medium to strong water-wetability. The heavy oil consists of high resin content (21.2 - 27.5%), high acidity (3.15 - 6.48 KOH mg/g oil), and high viscosity (2642 - 253727 mPa.s). The viscosity value decreases about 9 to 44 times when the temperature increases from 20 to 50°C. On the other hand, the heavy oil consists of low wax content (2%), low sulphur content (0.5%), low pour point (16 to 24°C), and low asphalt content (1.1 to 5.67% measured at 30 to 60 °C). The heavy oil belongs to the cyclic alkane to intermediate oil family. The reservoirs have low pressure (1.8 to 4 MPa), temperature (16 to 27°C), and low solution gas (5 m3 / mm^3).

■ Reservoir Types.

The heavy oil occurs in three of the four reservoir types discussed in the previous sections. They are : (1) onlap sediments on top of the main overthrust body (Fig. 6) where about 85% of the total resources is located; (2) the downthrow wall (Fig.7); and, (3) the crystalline basement rock below unconformity surfaces.

ORIGINS OF THE HEAVY OIL

The processes for the formations of the heavy oil in the northwestern Junggar basin can be summarized as follows:

(1) The overthrust moved the favorable reservoirs to the vicinity of the source rock shortening the migration path in the basin.

(2) Multiple tectonic events provided a mechanism for oil migrations. The first event occurred at the late Triassic, where migration produced Permian-Triassic reservoirs. The second event during the Jurassic-Cretaceous was much weaker than the first event. The third event occurred at the Late Yanshan movement. This event re-distributed the oil and gas reservoirs, and the oil migrated into shallow reservoirs. The tar sand and asphalt were formed during this event. Some of the light crude oil was lost on the unconformity surface.

(3) Oil occurring within the overthrust belt came from the same source rock. From geochemical studies, the light and heavy oils, occurring at the deep and shallow horizons, have the same characteristics. For example, the relative content of steranes, C_{27} (6 - 13%), C_{28} (40 - 44%), C_{29} (46 - 53%) are consistent for all oils(Table 3), and are clustered together on the ternary plot (Fig. 8).

(4) The specific gravity of the oils changes from light at the deep end of the basin to heavy at the shallow end (Table 4).

(5) Biodegradation is the major factor for the origin of the heavy oil. The biomarker compounds identified from the heavy oils are steranes, hopanes, special sterane compounds (diasteranes), tricyclic diterpanes, degradated steranes, and terpanes, alkyl cyclopentane, CH_4, and carotane.

The cross section of the Karamay oil field (Fig. 9) begins with block 5 (downthrow wall) proceeding to block 4 (front faulted zone), to block 3 (hanging wall), and extending to the north. The physical properties of the heavy oil samples along this section change from light to heavy and then into tar sand (Table 5). The order of biodegradation among the biomarker compounds are: n-alkane, alkyl cyclopentane, isoprenoid alkane, bicyclic sesquiterpane, γ-carotane, regular sterane (20R), β-carotane, regular sterane (20R), pregnane, homopreganane, pentacylic triterpane, C_{20} - C_{29} tricyclic diterpanes, rearranged sterane, 13,17 seco-sterane. The biomarkers having high resistance to organic degradation are 25-norhopane, 25,30bisnorhopane, C24H42 tetracyclic diterpane, 17 α (H)-22, 29, 30 trisnorhopane (Tm), gammacerane, various lupane, C_{33} - C_{38} (no C_{37}) tricyclic diterpanes and C_{27} and C_{29} - C_{31} 8,14-secohopanes (Figs. 10, 11, 12).

The other evidence of the biodegradation process is the discovery of the "de-waxing bacteria" cultivated in the soil samples from block 3 of the Karamay oil field where heavy oil reservoirs occur. The bacteria have strong ability to feed on wax. According to the experiments, at a temperature of 30± 1°C the bacteria can decrease the pour point of the oil from +13 °C to -50 °C when cultivated with mixing fluids for three days. The "de-waxing bacteria" have been used to eliminate the wax from crude oil successfully. This evidence strongly suggests that the "de-waxing bacteria" are active in the shallow reservoirs. Consequently, this de-waxing process can reduce the amount of n-alkane considerably, lower the pour point, and increase the viscosity and the specific gravity of the heavy oil. On the other hand, the heavy oil reservoirs were subjected to flushing by meteoric water and air. The original oil therefore has undergone oxidation and degradation, and was changed into heavy oil.

CONCLUSIONS

☐ *(1) The heavy oil that occurs in the northwestern Junggar basin is distributed in a very extensive area.*

It is buried at several shallow stratigraphic horizons. The reservoirs have low pressure and temperature, and high contents of resins, high acidity, and high viscosity, but low wax content, low pour point, and low asphalt content.

☐ *(2) The major reservoir type is an onlap on an unconformity surface.*

☐ *(3) The history of the heavy oil formation shows that it was subjected to several stages of change. The oil had migrated two or three times into the overthrust belt. It was then subjected to biodegradation, and degradation by meteoric water and to oxidation by air.*

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- 2. Yang Bin: "Bio-degradation of Crude Oil in Karamay oil field", The Third National Geochemistry Symposium, 1986
- 3. Liu Jingkui: " Study on the Very Thick Conglomerate Reservoir in Karamay oil field", Acta Petrolei Sinica of China, 1986, no.1.

Table 1

Geochemical Characteristics of Some Rocks from the Junggar Basin

Region	System	HOC %	Chloroform "A" (ppm)	Organic Type	Vitrinite R_o %	Source rock Maturation/ Evaluation
Southern	-J_1	0.77	360	Humic mixed	0.66	Low mature Good
	T_3	1.44	546	Mix	0.73	Mature Poor/Good
	P_2	10	3949	Sapropel - Mix	0.68	Mature Excellent
	P_1	0.86	721	Sapropel	1.62	High Mature/Good
Tuo-shi-tai	E_{1-2a}	1.13	823	Sapropel		Immature Good
Xi-Can2	E_{1-2a}	0.62	174	Sapropel		Immature/ Poor
North-western	-J_1	1.99	583	Humic-Sapropel	0.5-0.64	Immature Good
	T_3	1.31	358	Humic-Sapropel	0.41-0.78	Immature/ Poor
	P_2	1.01	283	Humic	0.51-1.86	Mature/ Poor
	P_1	1.26	1493	Humic-Sapropel	0.75-1.86	Mature/ Good

Table 2

Reservoir Characteristics of the Junggar Basin

Region	System	Lithology /Facies	Pore Type	Porosity (%)	Permeability (mm m^2)
Southern	N_1	Sandstone Fluvial	Intergranular	15-18	0.009-0.2
	J_2	Sandstone Fluvial	Intergranular	9-23	0.001-0.1
North western	K_1	Sandstone Fluvial	Intergranular	30-35	1.7 - 3.2
	$^1J_3$	Sandstone Fluvial	Intergranular	25-34	0.5 - 5.0
	$^1J_1$	Sandstone Conglomerate Braided R	Intergranular	20	0.005-0.112
	$^2T_2$	Sandstone Conglomerate Braided R	Intergranular	18 - 22	0.08-0.15
	$^1T_2$	Sandstone Conglomerate Braided R	Intergranular	15 - 20	0.05-0.1
	T_1	Conglomerate Diluvial	Intergranular Secondary	10 - 15	0.05
	$^2P_2$	Conglomerate Diluvial	Secondary	6 - 13	<0.001
	$1P_2$	Conglomerate Diluvial	Secondary	9	<0.001
	$^2P_1$	Argillaceous Dolomite	Dissolved Micro-fracture	6	0.0002
	$^1P_1$	Volcanic Laparite Andesite Pyroclast	Dissolved	6 - 9	<0.001
	C_1	Volcanic Andesite Basalt	Fracture Dissolved pore	6 - 9	<0.001
East	T_1	Sandstone	Intergranular	12 - 18	0.008-015
	P_2	Siltstone Dolomite Lake delta	Dissolved Fracture	8 - 17	0.001-0.2

Table 3

Steran (C_{27-29}) Characteristics in Oil from the Feng-chen Anticline

Well No	System	Depth (m)	C_{27}(%)	C_{28}(%)	C_{29}(%)
Wu-er-he	K_1	Asphalt block surface sandstone	8	39	54
	K_1	Asphalt veins	9	44	48
	K_1	70.0 - 100.0	8	52	40
Feng 5	C_3-P	739.95-742.55	8	39	54
Wu 5	$^{1}T_2$	1490.0 - 1415.0	6	43	51
135	P_2	2784.0 - 3064.0	6	42	52
Feng	P_1	3200.0 - 3233.0	6	40	54
Feng 3	P_1	3243.0 - 3249.0	7	40	53
Feng 6	P_1	3466.6 - 3466.92	5	37	58

Table 4

The Specific Gravity and Viscosity of Oil from the Karamay Oil Field

Block	System	Structural Style	Gravity d_4^{20}	Viscosity $MP_a.s$
6-9	$^{1}J_3$	Onlap pinch out	0.92-0.96	800.0
6	$^{2}T_2$	Main overthrust	0.885-0.90	77.0-215.0
	$^{1}T_2$	Main overthrust	0.899	80.0
7	$^{1}J_1$	Front faulted	0.865	8.5
	$^{2}T_2$	Front faulted	0.867-0.876	5.6-7.6
	$^{1}T_2$	Front faulted	0.852-0.863	6.0-6.2
	$^{1}P_1$	Front faulted	0.865	4.0
8	$^{1}J_1$	Overthrust Outer front	0.865-0.876	8.0-8.2
	$^{2}T_2$	Overthrust Outer front	0.854	1.9
	$^{1}T_2$	Overthrust Outer front	0.85	3.8
	$^{1}P_{2w}$	Overthrust Outer front	0.842	0.7

Table 5

Physical and Chemical Properties of Oil from the Junggar Basin

Well no		5153	310	50	3245
Depth interval(m)		1604.1- 1525.8	688- 640	586- 513	468.8- 457.8
System		$^1T_2$	$^1T_2$	$^1T_2$	$^2T_2$
Sample Type		Oil	Oil	Oil	Oil
A	Gravity D_4^{20}	0.8445	0.8508	0.8730	0.8754
	Viscosity(30 °C)	36.8(26 °C)	17.5	100.89	93.14(20°C)
	Pout pt °C	+1.0	-32.5	-35.5	-51.5
	Wax %	8.92	4.55	3.28	1.25
B	Saturated hydrocarbon	71.3	69.3	65.3	58.3
	Aromatic %	13.4	14.6	17.11	18.9
	Non HC %	5.0	10.9	12.1	18.3
	Asphalt %	10.3	5.2	5.5	4.5
C	N_1 ppm	7.77	2.10	4.24	2.79
	Van ppm	0	0	0	0
D	N_1 ppm	9.17	3.23	9.17	8.20
	Van ppm	0.10	0.03	0.07	0.15
E	iC_{19} / nC_{17}	0.71	0.79/1.01*	1.16	1.39
	iC_{20} / nC_{18}	0.79	0.97/1.30*	1.20	1.41
	$iC_{19} + C_{20}$ $nC_{17} + C^1_8$	0.75	0.87/1.15*	1.20	1.41
Oil	^{13}C °/$_{oo}$	-29.842	-29.681	-29.759	-

A: Physical properties; B: Composition of hydrocarbon;
C: Porphyrins; D: Oil; E: Gas chromatography

Table 5. Continued

	Well no	Black oil Mt.	Ka Reservoir	Tu-zi-guo
	Depth Interval (m)	Surface	Surface	Surface
	System	$^{2}T_{2}$	$^{1}T_{2}$	J_{1}
	Sample type	Oil	Oil sand	Oil sand
A	Gravity D_4^{20}	0.817	-	-
	Viscosity 30°C	442.58	-	-
	Pour pt °C	-31.2 -40.0	-	-
	Wax %	0.88 - 1.07	-	-
B	Saturated hydrocarbon %	52.85	32.55	33.81
	Aromatic %	14.94	4.99	7.20
	Non HC %	17.91	14.95	22.30
	Asphalt %	4.17	47.51	36.69
C	Ni ppm	2.98	0	0
	Van ppm	0	0	0
D	Ni ppm	16.27	-	11.17
	Van ppm	0.25	-	0.27
E	iC_{19} / nC_{17}	-	-	-
	iC_{20} / $nC^{1}{}_{8}$	-	-	-
	iC_{19} + iC_{20}	-	-	-
	nC_{17} + nC_{18}	-	-	-
	Oil ^{13}C °/$_{oo}$	-29.778	-29.047	-29.829

Note * Pay zone 622.75-599 m Saturation HC data on hanging wall 668 - 640 m Saturation HC data on downthrow wall
A: Physical properties; B: Composition of hydrocarbon;
C: Porphyrins; D: Oil; E: Gas chromatography

Figure 1

Tectonic Elements of the Junggar Basin. 1. Uplift; 2. Depression; 3. Heavy Oil Distribution

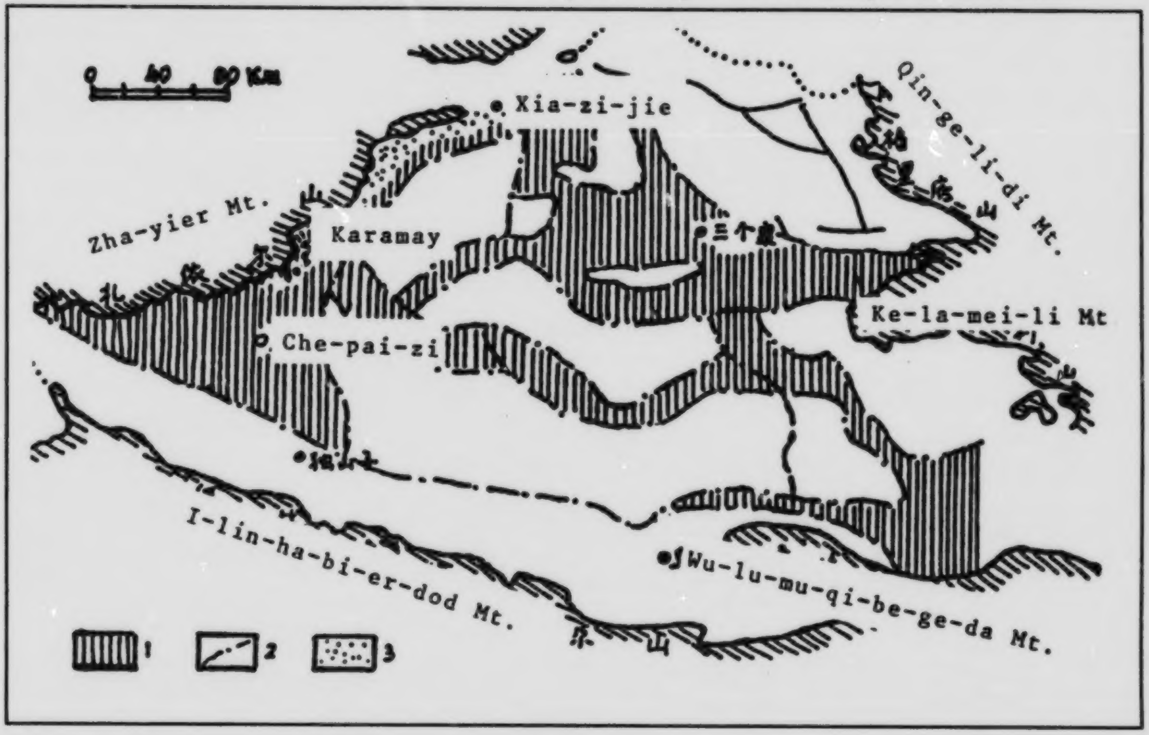

0 40 80 Km
Xia-zi-jie
Qin-ge-li-di Mt.
Zha-yier Mt.
Karamay
三个泉
Ke-la-mei-li Mt
Che-pai-zi
I-lin-ha-bi-er-dod Mt.
Wu-lu-mu-qi-be-ge-da Mt.
1
2
3

Figure 2

Cross Section Of The Overthrust Belt

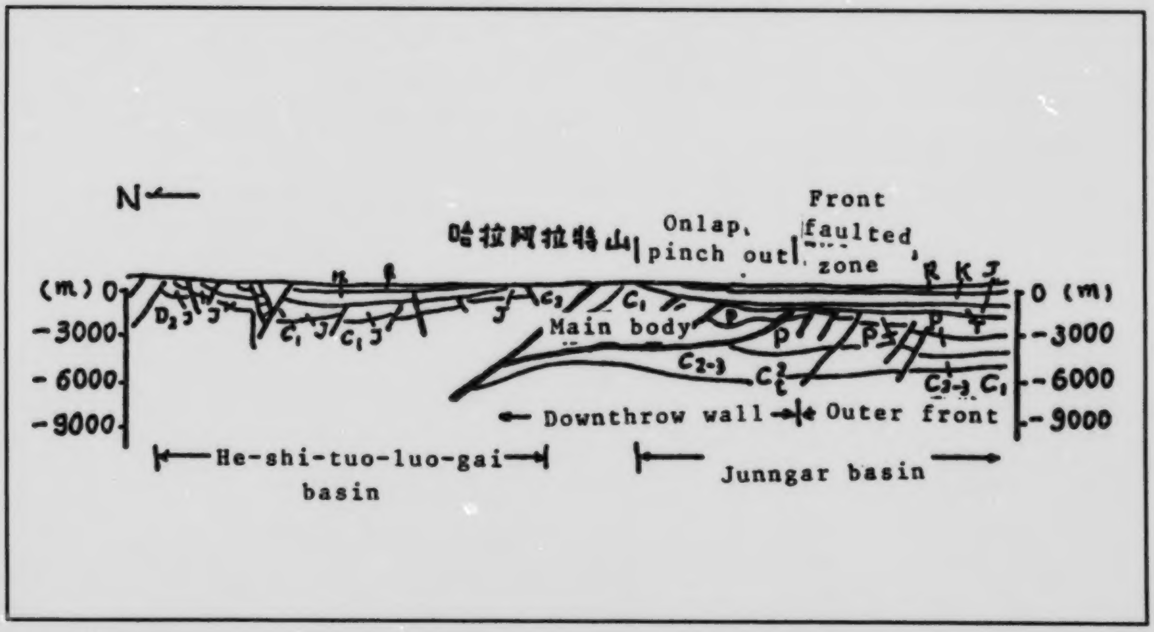

N
哈拉阿拉特山
Onlap, pinch out
Front faulted zone
(m) 0
-3000
-6000
-9000
0 (m)
-3000
-6000
-9000
D2
J
C1
C2
Main body
P
C2-3
R
K
J
Downthrow wall
Outer front
He-shi-tuo-luo-gai basin
Junngar basin

Figure 3

Cross Section Of The Karamay Oil Field. 1. Light Oil; 2. Heavy Oil

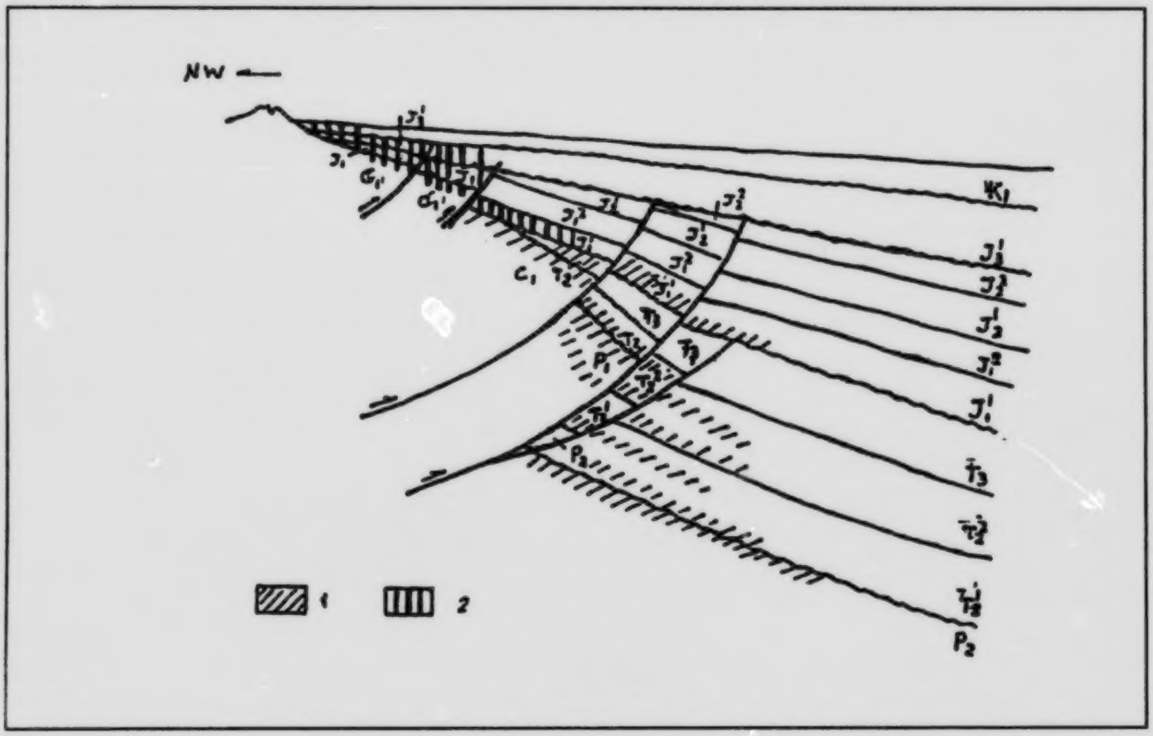

NW ←
K1
J3^1
J3^2
J2^1
J1^2
J1^1
T3
T2^2
T2^1
P2
C1
P1
1
2

Figure 4

Migration Paths and Traps in the Northern Junggar Basin. 1. Primary Migration Path; 2. Secondary Migration Paths; 3. Accumulated Locations

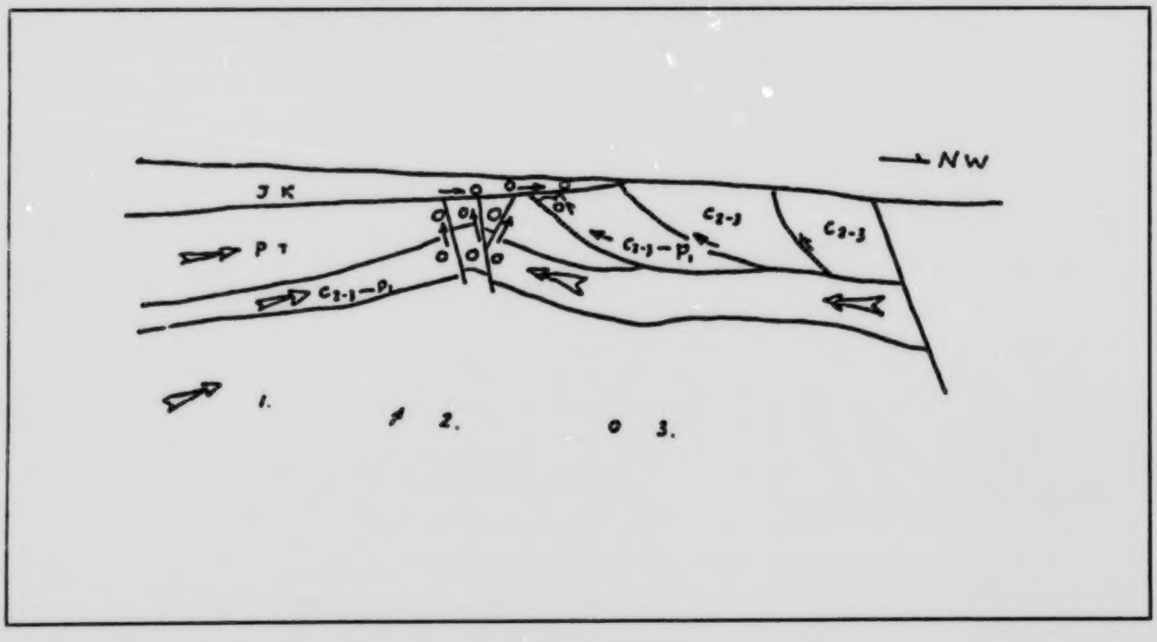

→ NW
J K
P T
C2-3 — P1
C1-3 — P1
C2-3
C2-3
1.
2.
3.

Figure 5

Migration Pattern Related to the Geological Setting of the Junggar Basin. 1. Lower Permian Source Rock; 2. Upper Permian Source Rock; 3. Faults; 4. Migration Paths.

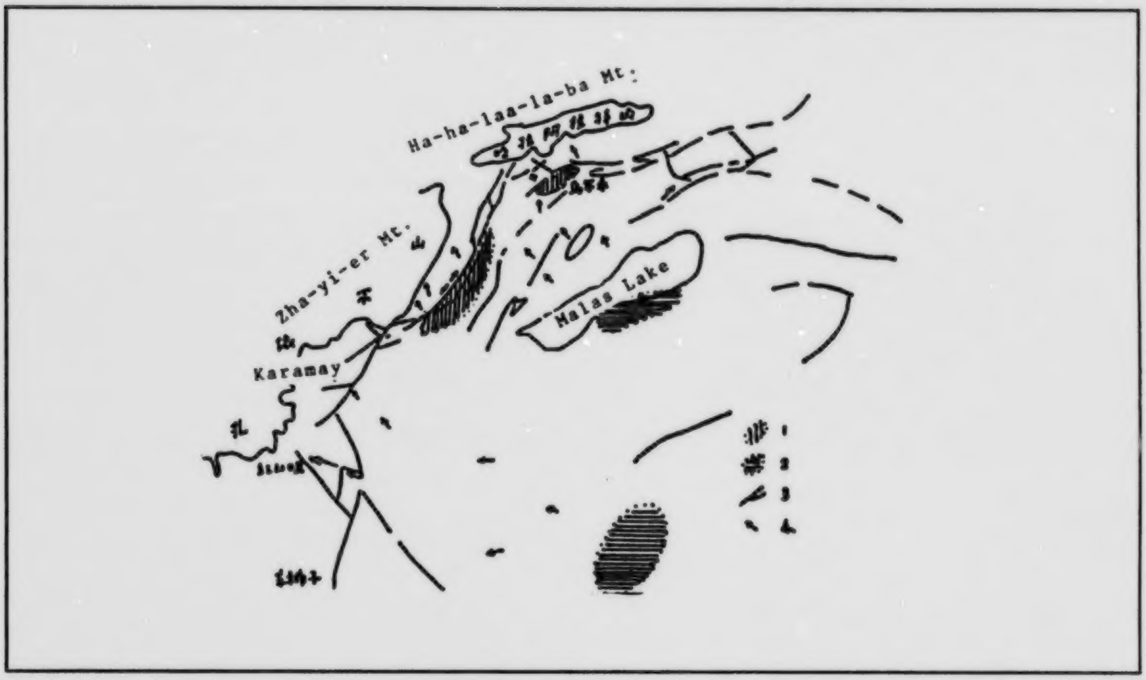

Ha-ha-laa-la-ba Mt.
Zha-yi-er Mt.
Karamay
Malas Lake
1
2
3
4

Figure 6

Cross Section of the Feng-cheng-cheng Area. 1. Heavy Oil; 2. Tar Sand.

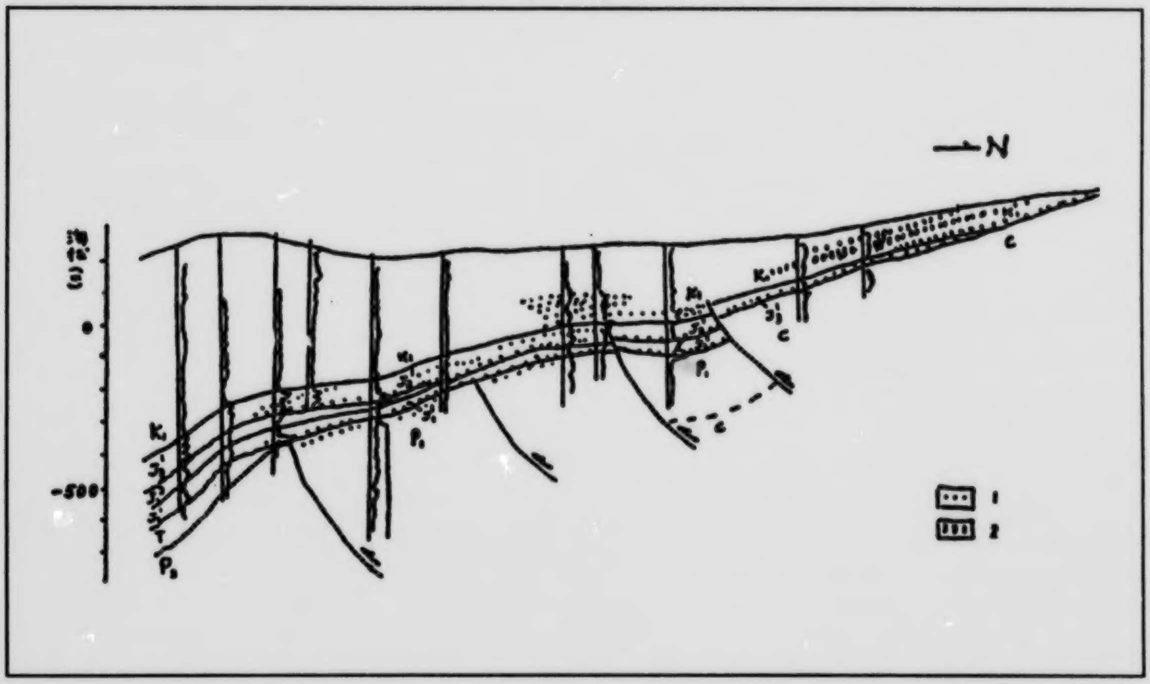

N
0
-500
K₁
J
T
P₂
P₁
C
1
2

Figure 7

Cross Section of the Structure of the Hong No. 1 District

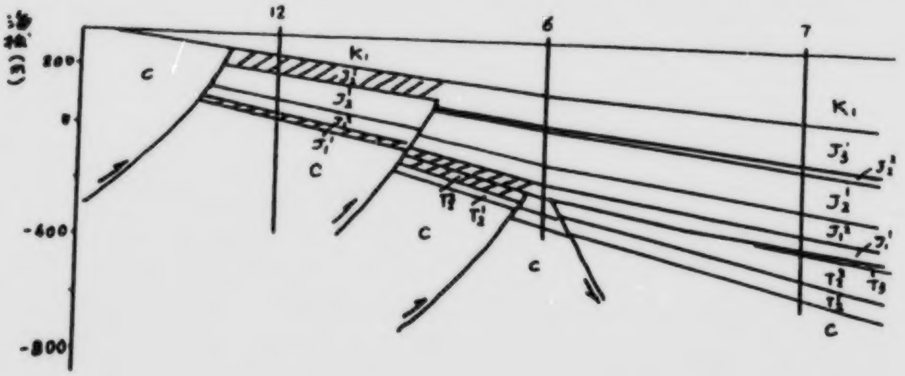

海拔 (m)
200
0
-400
-800
12
6
7
K1
C
J3'
J2'
J1'
C
T2'
C
C
K1
J3'
J2'
J1'
T
C

Figure 8

Ternary Plot of the C_{27}-C_{29} Steranes from the Karamay Oil Field

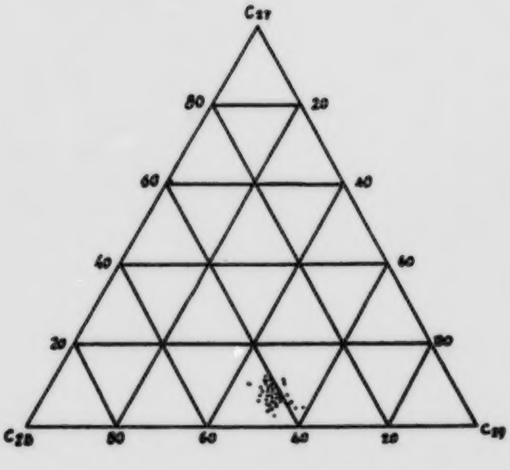


Figure 9

Geological Cross Section from the District 5 of the Karamay Oil Field to the Tz-zi-guo area. 1. Light Oil; 2. Heavy Oil; 3. Tar Sand.

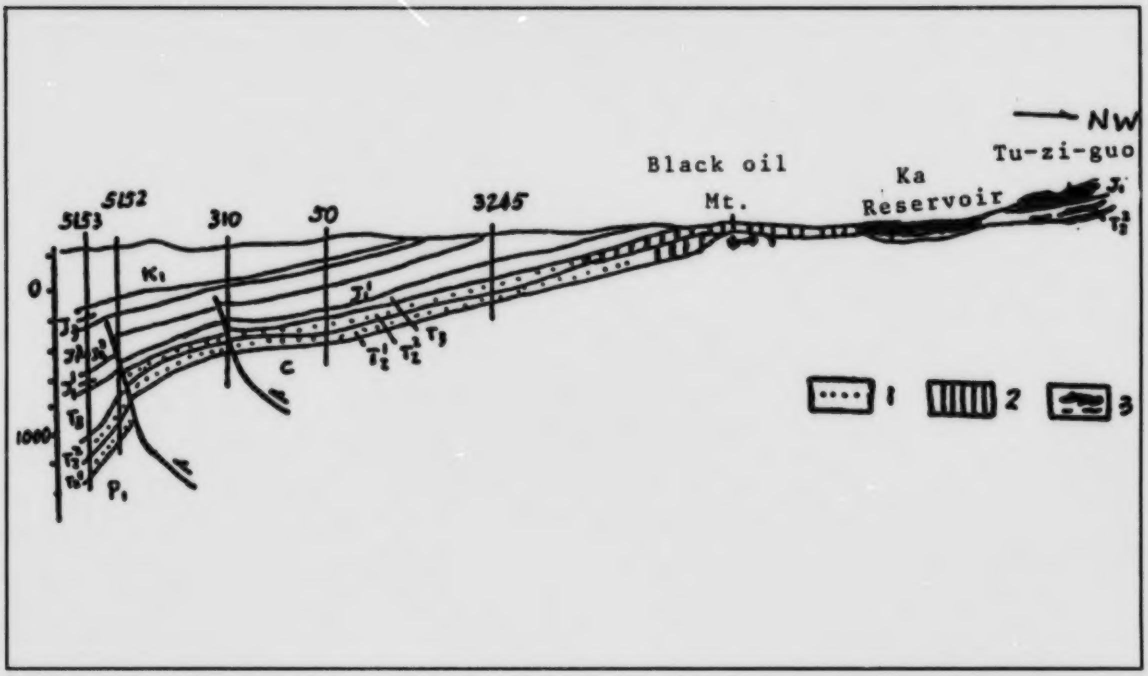

NW
Tu-zi-guo
Black oil
Mt.
Ka
Reservoir
5153
5152
310
30
3245
K1
0
1000
J1
T3
C
P1
1
2
3

Figure 10

The Gas Chromatograms of Triterpanes of the Cross Section (Fig. 9). A: Tu-zi-gou surface tar sand; B: Ka Reservoir Surface Tar Sand; C: Black Oil Mt. Surface Tar Sand; D: Well 3245 Crude Oil; E: Well 5153 Crude Oil

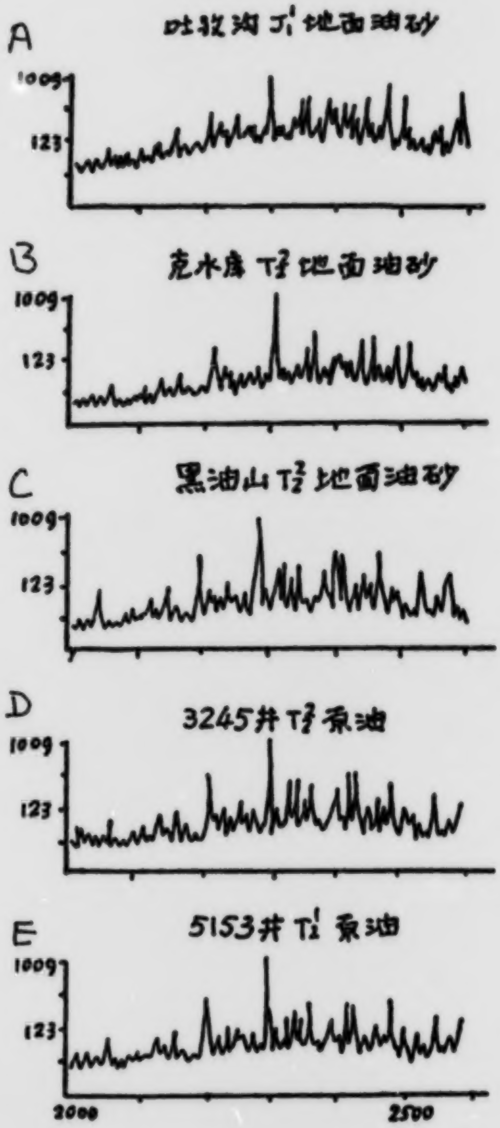


Figure 11

The Gas Chromatograms of Crude Oil from Well 563 of the Cross Section (fig. 9). A: Well 5153 CrudeOil; B: Well 3245 Crude Oil; C: Black Oil Mt; D: Ka Reservoir; E: Tu-zi-guo Surface Tar Sand

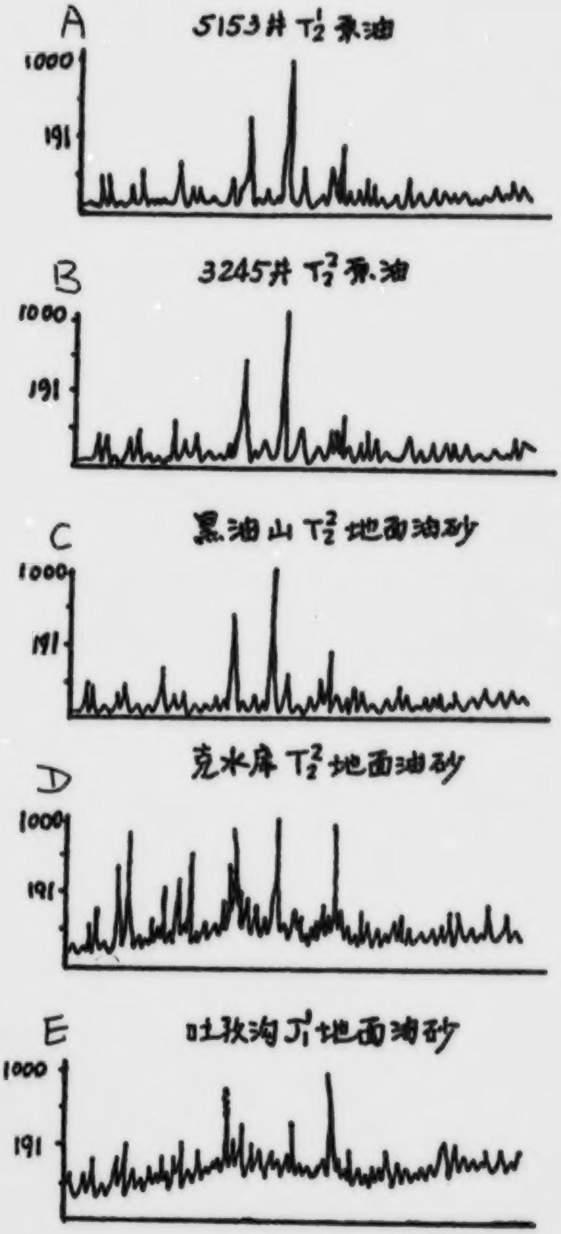
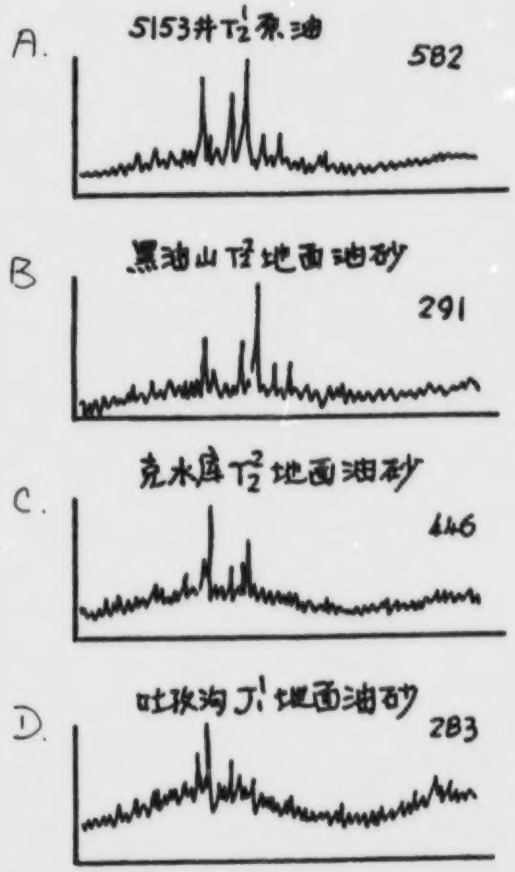


Figure 12

The Gas Chromatograms (m/e) 177 of the Crude Oil from A: Well 5135; B: Black Oil Mt. Surface Tar Sand; C: Ka Reservoir Surface Tar Sand; D: Tu-zi-guo Surface Tar Sand



7

THE ROLE OF RESERVOIR ENGINEERING RESEARCH

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ABSTRACT

The traditional method of developing a commercial recovery process has been to test a proposed recovery process in a field pilot and then to scale-up the field data to commercial size. To complement field data, a reservoir engineering research program would be undertaken, usually involving scaled model experiments, to determine key process parameters and to evaluate alternate operating strategies not tested in the field. Results from the experimental research program would be combined with field data in a numerical reservoir model which then became a primary tool by which reservoir engineering groups finalized the design of the commercial project.

The numerical reservoir model has become increasingly sophisticated. Incorporation of advanced models of the recovery process when coupled with an advanced capability of representing reservoir characteristics and the increased speed of modern computers has placed a powerful tool in the hands of the reservoir engineer. This enhanced capability has led some to question the role of the complementary engineering research program. The argument presented is that since basic data can be obtained by technical service groups, and reservoir studies can be done by the reservoir engineering groups, why do we need a reservoir engineering research group?

This paper outlines the role of a modern reservoir engineering research group and, by way of a number of examples, shows where reservoir engineering research still has a major role to play.

INTRODUCTION

Back to the Basics

The production of oil has proceeded from the simple to the more complex. In the early days, the technology essential to the success of an oil company was its ability to find conventional oil reservoirs. Once found, wells were drilled and oil produced. As oil production declined, new wells would be drilled or better ways of producing the existing wells were sought. As we sought better ways of producing existing fields, the science of reservoir engineering was born.

In North America, the research required to support reservoir engineering was performed by reservoir engineering research groups. These groups have traditionally fulfilled three roles. Firstly, they did the basic service work required to evaluate a field prospect: PVT data, data, relative permeability, capillary pressure, etc., and in some companies even the basic core work such as oil and water saturation, screen analyses, etc. Secondly, they studied the basic phenomena controlling the recovery process which may be occurring in a reservoir. Thirdly, they looked at a series of potential recovery scenarios which may be employed for recovering hydrocarbons from a resource and, where things looked promising, have conducted field pilot tests on the process. Such pilots were usually performed in existing fields using equipment and personnel in place. Successful technology was then transferred to the production department.

Through research, the basic mechanisms that govern primary production and water flooding in conventional oil reservoirs were learned. The constitutive equations which govern these processes were developed and analytical and numerical solutions obtained which enabled the reservoir engineers to plan and predict recovery schemes and transfer technology from one geological setting to another. The role of engineering research in this technological development was seen to be complementary to that of the reservoir engineering and production engineering groups.

However, the environment was changing. As conventional oil reservoirs were being commercially exploited, attention shifted to reservoirs in which primary production and follow-up water flooding did not yield a commercially viable process. Most commonly, these were the heavy oil and oil sand reservoirs, and to effectively recover the hydrocarbon resource, a new process technology was required. This led to the field and laboratory testing of novel and innovative recovery processes, including steam soak, combustion and steam drive. In this technology development process, engineering reservoir research was called on to play a leading role in the process design and prediction of performance for a field trial in addition to its traditional complementary role.

Prediction of Performance: Laboratory to Field

Prediction of performance can be broadly grouped into two distinct philosophies and approaches, each of which has its champions and schools of adherents(1). These different but interlocking approaches are schematically illustrated in Figure 1. In order to put a label on these approaches, they may be classified as "scaled" models and "elemental" models. In a scaled model, one attempts to produce a miniature of the proposed field operation according to some scaling criteria; in an elemental or unscaled model, one isolates a distinct element of the larger field case and conducts a series of experiments on that element at conditions as close as possible to the field.

In the scaled model approach, it must be first decided what scaling criteria are to be met, and this in turn is dependent on the intended use of the model. By neglecting those parameters which are not important and using ingenuity to scale those factors which are important, it is possible to construct scaled models which simulate field conditions reasonably well. A major limitation of the scaled model approach, however, is that a scaled model study is time consuming, expensive and the results from such a study are not easily projected to reservoir conditions other than those studied.

The elemental or unscaled model approach relies, in effect, on whether a suitable mathematical model to predict field behavior can be developed. This model could be anything from a simple correlation to a detailed numerical reservoir model, but in any case, represents the primary mode of transfer of technology from the laboratory to field application.

A classic example of the success of the scaled model approach was the development of the cyclic pressure stream drive process by Shell Oil Company(2). In this development, scaling criteria were developed for a low pressure physical model and this model was then used to evaluate various steam recovery processes in a number of reservoirs such as Mt. Poso and Midway Sunset. The encouraging production performance predicted by these models led to successful pilots in these reservoirs and, subsequently, commercial operations. The development concept was extended to the Peace River oil sands deposit where it was noted that because of the high permeability and water saturation in the low 3 m of the deposit, highest ultimate recovery and production rates were achieved by an interwell pressure cyclic drive process. Field testing of this concept proceeded with AOSTRA's assistance in the 1975-1985 period and this has subsequently led to commercial production which is getting underway.

Numerical Simulation

In 1977, Prats(3) was asked that if he had to do it over again, would he have proceeded in the same way. He replied that with the advances which had occurred in numerical simulation, the study including the variations and the ultimate process developed could now be carried out much more cost effectively by numerical simulation. This is understandable since although physical models can be used to portray most mechanisms of a steam flood accurately, they are still time consuming to pack and operate and often are limited by availability of materials and fluids to achieve proper scaling for particular oils and sands.

Since 1977, computer software and hardware have continued to develop at a very rapid rate. The numerical reservoir model has become increasingly sophisticated. Incorporation of advanced models of the recovery process when coupled with an advanced capability of representing reservoir characteristics and the increased speed of modern computers has enabled the reservoir engineer to more accurately portray and predict field performance. Mathews(4) has recently (1983) stated that mathematical reservoir simulation is now the fastest, most accurate and most efficient method for predicting performance of steam floods in well defined reservoirs with intermediate viscosities (less than 10,000 cp at reservoir temperature).

In general, but not exclusively, there are a variety of problems with the use of mathematical models. These include:

1. The uncertainty of having identified the appropriate fluid flow, heat and mass transfer mechanisms for inclusion in the model;

2. The difficulty in obtaining suitable physical property and parameters data as required by the identified mechanisms;

3. The definition of appropriate grid networks and boundary conditions.

If these problems can be appropriately resolved, then the advantages through use of a numerical reservoir model to predict field performance are considerable. An appropriate numerical reservoir model, once it has been systematically checked and verified can be employed by both research and reservoir engineering in a wide range of design, prediction and evaluation studies. As such, it is a pre-eminent tool of general use.

■ The Current Problem

We seek, however, to recover oil from increasingly difficult situations using increasingly complex and not well understood recovery processes. Some of these are:

- ☐ *Recovery of a completely dead oil of very high viscosity such as Athabasca bitumen*
- ☐ *Recovery of oil where injectivity can only be obtained by fracturing*
- ☐ *Recovery of heavy oil with gas caps and/or large amounts of bottom water*
- ☐ *Recovery of light and heavy oil in dual porosity formations, e.g., fractured carbonates*
- ☐ *Combustion systems*
- ☐ *Miscible displacement*
- ☐ *The use of additives with steam*
- ☐ *The use of foams, surfactants, and emulsions*
- ☐ *Viscous fingering and non-Darcy flow*

The status of our understanding of these complex recovery processes both in the laboratory and under simulated "ideal" reservoir configurations is incomplete and in many respects lags the testing of these processes in the field. Through necessity, reservoir engineering groups have modified reservoir models in an attempt to capture as best as possible the apparent dominant mechanisms of the recovery process. These models, tuned or calibrated against field data, have been used to predict various recovery options, with mixed results. The net result, however, has been that so called "research" is now performed by reservoir engineering groups.

In many studies, the model is being used competently and results from numerical studies provide the guidance expected from such studies. An essential problem, however, is that in some studies, and specifically in those instances involving scoping of novel or complex recovery processes, the assumptions made by the reservoir engineering groups, although necessary if such studies are to be performed, have not been realistically checked or verified against laboratory experimental data. In these cases, the use of numerical simulation gives an answer, but can we believe that answer? Since the models are not mechanis tically correct, either on a micro and/or macro-scale we resort to fudgefactors to obtain a prediction or a history match to a particular field test. Can such "history" matches truly be a useful tool in transferring technology from one reservoir to another or are the fudge-factors going to have to change as the reservoir characteristics change? Then too, since we often do not know what is really going on in a field test, but only the input and output parameters, where do we tie our numerical model to reality or is it just a mathematical fiction or an elaborate correlation tool?

To add further complexity, Carrigy(5) has recently stated:

> *"Considerable evidence supports the thesis that the success of an in situ pilot results more from a choice of reservoir than from the engineering effort that goes into hardware and operating strategy. Probably the most significant lesson that has been learned from the many field pilot tests in oil sands is that unpredictable variability in the reservoir is the most important factor militating against the success of field experiments".*

The implications then are quite clear. If the recovery process is complex and incompletely understood, and being applied in a reservoir of unpredictable variability, then how does an engineering research program being performed in a laboratory setting contribute to the ultimate objective of a commercial project? To take the argument one step further, if special and routine analyses are being done by service laboratories (e.g. core laboratories, chemical and geological laboratories, etc.) and with much of the traditional reservoir engineering research being done by numerical simulation, is there a role for a reservoir engineering research group?

These questions will be addressed in the remaining sections of this paper.

A REVIEW OF THE CURRENT STATUS OF ENGINEERING RESERVOIR RESEARCH

In the previous section, a review of the perceived status and problems facing engineering reservoir research were outlined. In this section, the technical underpinnings and challenges which have contributed to this perceptual view will be presented.

The incentives which form the basis for an effective engineering research program are quite easily stated. The costs of carrying out field recovery tests of processes are very high. A small pilot would cost twenty million dollars, while a larger pilot with anticipated field spacing between wells and several patterns may cost one hundred million dollars or more. Turn-around time from a pilot is slow, requiring 3 to 6 years to obtain results from a single test and since many factors such as site geology are ill-defined, it is often difficult to interpret results in general process terms. For these reasons it is desirable to examine a recovery process in lower cost, faster and more reliable laboratory experiments.

The technical difficulties in achieving this objective are two-fold. Firstly, the variability and characteristics of the reservoir which may have an impact on results from the research program must be quantitatively understood and incorporated into the design of the research program. Secondly, results from the research program must be projectable to and interpretable in terms of their impact on the field. These are not new difficulties; they are the traditional difficulties. What is new, however, is that the leap to develop and test new technologies in the field has dramatically outstripped the technological base available in engineering research. And this has happened at a time in our technological development when engineering research could and should be exerting its most definitive role.

The challenge then to engineering reservoir research is simply stated. It is to close the gap between the current technological base and the requirements of the reservoir engineers who must design and operate commercial recovery processes. In the following section, a set of roles which appropriately define the activities of a modern engineering research group will be outlined.

DEFINED ROLES FOR ENGINEERING RESEARCH

To close the current technological gap, a modern reservoir engineering research program must address and satisfy three outstanding needs. These are: (i) the need for *innovative* research, (ii) the need for *development of advanced capability,* and (iii) the need to expeditiously respond to and solve identified field problems through the *application* of advanced technological tools. The role of engineering research, therefore, is a multipurpose role, and is defined by its technological capability in responding to and satisfying these needs.

Clearly, in developing a research program to fulfill a multipurpose role, an appropriate sense of balance and of priorities between the respective needs and roles is required. In the short term, it is possible to emphasize one role in preference to another, and the program should have both the responsiveness and flexibility to accommodate adjustments in priority. However, in the longer term, the program must achieve an appropriate balance in response to these technological needs if it is to close the current technological gap.

In the following sections, the multipurpose role of engineering research will be further examined and then illustrated with specific examples which reinforce that role.

THE ROLE OF INNOVATION

Innovation, as characterized by the generation and assessment of new and novel process concepts, is an essential feature of a comprehensive research program. In practical terms, a technical infrastructure must be in place which provides a first level of testing and evaluation of novel ideas on an appropriate scale and in a timely, cost effective fashion. Most commonly, this will involve experimental test apparatus, ranging in size from small scale, in which an experiment can be proposed, designed and completed in less than a week, up to larger scale facilities which may require several weeks to turn around. Facilities of this size lend themselves to preliminary scoping studies and if appropriately instrumented can lead to first level characterization of dominant recovery mechanisms. A recent publication(6) has described such a set of facilities.

In the following, an example of the role of innovation which led to field trials of a novel recovery process, and which then subsequently led to new research directions will be illustrated.

Steam-Naphtha Process

During the period 1973 to the present, Texaco Resources Canada Ltd. conducted a series of three pilots at their Fort McMurray lease. These pilots were of steam-based recovery processes with additives and were conducted in a shallow deposit (85 m overburden) with a good net pay of 36 m. The patterns used are shown in Figure 2.

The first pilot, Pattern I, was a 4 ha nine-spot with central injection. Interwell spacing varied between 100 m and 141 m. Communication was achieved between closer injectors and producers. However, difficulty was experienced in developing communication within a reasonable time frame over the longer distances. Once hot communication was achieved, recovery by steam-alone was low and improvements to the recovery scheme were sought through the use of additives to steam.

In response to the identified need, a laboratory research program was initiated. The use of a wide variety of hydrocarbons together with steam was investigated(7) in physical simulators as a means of improving both overall recovery and other process parameters (e.g. thermal efficiency). A range of hydrocarbons from methane through ethane, propane, butane, pentane, natural gas, to synthetic crude were tested as additives in cyclic steam drive process. Based on test results obtained(7) (Figure 3), the addition of naphtha to steam resulted in a substantial improvement in recovery and appeared to be the most promising additive. The mechanism for the improvement has been identified(8) as a reduction in the residual saturation in the water swept zone.

Naphtha and steam in a drive with pressure depletion cycles were subsequently tried in Pattern II, shown in Figure 1. This second pilot consisted of a 1.5 ha enclosed seven-spot with central and peripheral steam injection. With the reduced interwell spacing, good communication was achieved throughout the pattern. Once hot communication was achieved, principal recovery was by means of the injection of steam with naphtha. Pressure buildup and depletion cycles were employed and the over-all process was termed the Interwell Vertical Steam Stimulation Process. Total recovery was in excess of 50% of the oil-in-place and, as shown in Figure 4, closely paralleled results from the physical simulator tests.

In parallel to this testing, and subsequently, other steam additives have been investigated in the laboratory (as part of the innovation process). The use of gases, with steam in various strategies forms our most mature experience base.

Figure 5 shows a comparison of the recoveries obtained in the lab(8) during a cyclic steam drive process, and, that obtained when CO_2 was injected either commingled with the steam, or in an alternating slug type mode. As shown, CO_2 would appear to improve both the ultimate recovery, and also the initial rate of recovery. Other experiments(9), however, suggest that by appropriate injection strategies the same final recovery may be obtained utilizing steam alone or with CO_2, but, again confirm that the initial rates of recovery are improved.

As shown elsewhere(8,10) the improved rates of recovery were due to increased rates of expansion of the steam zone. The first reason for this is that the CO_2 dissolves in the bitumen and lowers its viscosity. Secondly, during the pressure drawdown cycle, the CO_2 comes out of the solution and provides a solution gas drive. A logical, and innovative extension to the steam-naphtha and steam-CO_2 test results was to test the dual additive (CO_2-naphtha) combination.

In Figure 6, a comparison of the baseline steam performance, steam-CO_2, and steam-naphtha performance is compared to that obtained using a combination of naphtha plus CO_2. This appears to be the most promising process and embodies both features reduced saturation in the swept zone, and an increased conformance in the test bed. This data forms the basis of a patent(11) which was granted to AOSTRA/ARC in 1981. A field trial of this process has been recently announced and will be performed in the near future.

Hence, the innovation process has led both to methods of improving recovery once hot communications have been obtained and an understanding of the mechanisms that dominate performance. Further, it has led to a new direction in our research program. Tools to allow improved methods of obtaining hot communication at commercially acceptable well spacings still remains an active area of innovative research.

THE ROLE OF DEVELOPMENT

A central role of an engineering research program is the sustained *development* of advanced technical capability which enables the systematic and progressive evaluation of complex recovery processes from the laboratory to the field. To do so, the capability of investigating and characterizing reservoir phenomena at in situ conditions must be developed using both theoretical and experimental techniques. A major feature of that capability is the development of a relevant numerical reservoir model.

The development of a relevant numerical reservoir model is best accomplished in collaboration with a sound, broadly based experimental program. This requires then that experimental apparatus and measurement techniques be developed which provide quantitative insight into the physical mechanisms prevailing both in the laboratory and in the field. If appropriately designed, such insight may be obtained from either scaled or elemental physical models, and in combination, provide a powerful basis for development of a reservoir model. The *development* of experimental apparatus, the design and assessment of relevant experiments and the quantitative incorporation of relevant physical mechanisms in a numerical reservoir model, then, is a clearly defined role for reservoir engineering research.

In the following example, the sequence of development of an advanced experimental capability to meet the needs of an advanced reservoir model is described.

■ Development of Advanced Experimental Apparatus

Well controlled laboratory experiments are the key to developing an understanding of the mechanisms governing bitumen recovery. In order to better understand the forces involved during the flow of process fluids during thermal recovery, it has been necessary to develop specialized methods, and instrumentation for flow "visualization" of high temperatures and pressure core floods. The visualization is accomplished by the application of x-ray techniques which can also give the quantitative values for fluid saturations that are required for any mathematical formulation of the flow behaviour.

This capability has evolved from one-dimensional single beam attenuation, to two-dimensional xeroradiography, and finally to full three-dimensional computed tomography. The first system, as shown in Figure 7, uses a single beam approach to directly measure bitumen and water saturations for relative permeability determinations on oil sand cores at in situ steam conditions. The second system, shown in Figure 8 utilizes x-ray xeroradiography, and is a qualitative technique developed to visualize encased field cores and coreflood experiments. The xeroradiography concept has a number of features which lead to high contrast, easily read, two-dimensional images of internal core structure and fluid distributions. The third system shown in Figure 9 utilizes xray computed tomography, and provides a full three-dimensional imaging capability. The image data is used to provide high resolution quantitative analysis of core structure and fluid saturations. The three complementary techniques provide a unique capability for the study of oil recovery processes.

Detailed results are available elsewhere(12). An example result is shown in Figure 10 which shows the flow patterns obtained during a hot water flood of an oil sand system. As expected, viscous fingering occurs due to the unfavorable mobility ratio. Future work will assess how to best incorporate the flow physics implied by pictures such as these, into any predictive model. Although conventional Darcy flow equations are of necessity used to assess the performance of large scale physical models and field situations, it is important to develop and maintain an understanding of how this simplified model compares to more detailed descriptions of the flow behaviour at a smaller scale.

■ The Role of Numerical Simulation in Process Development

In addition to its clearly identified role of predicting field performance, the numerical reservoir model can also be employed to assess and evaluate laboratory experiments and in so doing can provide a vehicle for resolving experimental detail as well as providing a "reality check" on the numerical model. The following example illustrates this feature.

■ Numerical Simulation of the Steam-Carbon Dioxide Process

One of the earliest additives tested in the laboratory to enhance the steam drive recovery process was carbon dioxide. Initial results obtained in unscaled physical simulators were quite encouraging (Figure 5) and warranted more comprehensive testing in larger scale apparatus. However, when such tests were performed, the improvement in recovery obtained was smaller then anticipated. This led to a detailed study of the experiments performed and to an improved understanding of the process(13), but because of differences in test bed configuration and operating strategy did not completely resolve the differences noted between experimental apparatus. This is a common problem, experienced not only in evaluation of laboratory data, but also in comparing results in field pilot tests.

To support the assessment of these experiments, a major development program was initiated to develop a steam-additive numerical reservoir model. Specific attention was directed to assuring that all recovery mechanisms believed to be relevant to the laboratory setting were incorporated in the model. The model developed has been described elsewhere(14).

Application of the model to the respective test bed geometries was not without some difficulty(15), but several clarifying features of the experiments became immediately apparent. First, the role of the initial communication path - its configuration and permeability relative to the surrounding oil sand - had a major influence on the rate and ultimate recovery obtained(16). Second, the recovery was quite sensitive to injection rate. Hence, in order to apply these experimental results to the field, some knowledge of the method contemplated for obtaining hot communications, which is prerequisite to the application of any successful process, must be obtained or postulated.

More recent work(13) has again highlighted the importance of the communication path/oil sands permeability contrast when naphtha alone is used as an additive. Hence, an essential part of our on going effort is to use the numerical models, *calibrated against all these experiments*, to determine under what conditions these additives might best be applied to field pilot tests. The models then are being effectively used to understand the mechanisms and important parameters that are operating in the physical simulators, both scaled and unscaled and in turn are being used to understand the mechanisms and parameters which are operating in a field scale test. Without identification of the dominant mechanisms, assessments done by numerical field predictions would be uncertain at best.

Development of Solutions to Operational Problems

Research has also developed solutions to operational problems. In thermal recovery projects utilizing vertical wells with slotted liners, unsatisfactory performance has been observed due to plugging of some slots, which leads to high velocities and erosion in others. This causes large amounts of sand to enter the wellbore and reduce production.

For processes utilizing horizontal wells the combination of unconsolidated oil sands and relatively low velocities make it likely that any sand entering the wells will settle and accumulate. Published data from an Elf-Aquitaine horizontal well project, and reports from the Texaco Athabasca pilot and San Ardo field, confirm that difficulties have been encountered with current sand exclusion techniques. Because of these problems, Texaco Canada Resources and the Alberta Research Council began a combined field and laboratory study of solids control methods suitable for the harsh conditions encountered during thermal recovery of heavy oil.

In order to study the overall behaviour of different solids control systems, a new experimental test cell (Figure 11) that could be operated with liquids or steam flowing through oil sands at high temperature and pressure had to be developed. The cell included an injection head, equipped to measure pressure and temperature, and a production head which separated the solids from the bitumen and water that is produced. A core of the formation to be tested was placed between the two heads and surrounded by a lead sleeve, to which external pressure was applied using nitrogen. This pressure simulates the effect of overburden loading. The solids control system to be tested was placed within the lead sleeve and between the sample and production head.

Various steam and hot water flows typical of thermal recovery conditions were then passed through the assembly utilizing the system shown in Figure 12 and various sand control devices evaluated(17). As a result, a patented(18) prepacked filter utilizing stainless steel wool sandwiched between coarse steel cloth was developed and successfully tested in both the laboratory and field(17).

A laboratory investigation using the same apparatus and techniques has been done to evaluate the effectiveness of this type of filter, and conventional slotted liners, for sand control in the horizontal wells of AOSTRA's Underground Test Facility. The elements selected(19) for field testing were:

1. Texaco Filter,
2. 0.010" wire wrapped screen,
3. 0.005" wire screen.

Hence, through a reservoir engineering research program, a new solution to an old problem was conceived, designed, field tested and has now been extended to a different field application.

THE ROLE OF APPLICATION

An additional, but not unsubstantial role for engineering research is the *application* of developed "tools" and/or technology to specific problems identified in the field. In this role, those "tools" that are appropriate to the problem are selected and assembled in a configuration which is appropriate to the defined problem. In such a role, engineering research provides a powerful combination of professional expertise and technology which is typically unavailable in technical service and/or reservoir engineering groups.

In the following, an example of the application of advanced research tools to an identified field problem is illustrated.

■ Application to Near Wellbore Formation Damage Problems

Cyclic steam stimulation is one of the methods under intensive investigation for the in situ recovery of bitumen and heavy oil in the Cold Lake region. One of the reservoirs of the region is commonly referred to as the "C" unit of Lower Cretaceous, Mannville group.

The Cold Lake deposit sands in particular, are mineralogically complex with quartz and feldspar grains, volcanic rock fragments, chert and clay. Kirk et al(20) have summarized the mineralogy of the Clearwater Formation in general. Quartz, potash feldspar, plagioclase, calcite, dolomite, siderite, pyrite, kaolinite, marcasite, muscovite, and biotite were identified by X-ray diffraction of the bulk sand; while kaolinite, illite, chlorite, smectite and mixed layer clays were found in the minus 2 μm sand fraction. The clay minerals can be less than 1% in the sands but up to 50% in the associated shales. Rock fragments can compose up to 30% of the sand and may have a more complex mineralogy. When steam-alone is injected into this mineralogically complex formation, severe plugging has been observed.

This identified field problem was brought to the laboratory and an experimental program initiated using available research apparatus. Laboratory research not only confirmed that the plugging is likely due to the formation of swelling clays, but also has provided the remedy.

Figure 13(a) shows an x-ray diffraction analysis of a sample taken from cores from this reservoir before and after being flooded with hot water in the lab. Also shown in Figure 13(b) are the core permeabilities before and after the floods.

As shown, with hot water alone there is a large growth of smectite clays Figure 13(a) and an attendant lowering of the permeability (Figure 13(b)). If a proprietary additive is used, the smectite clay growth is reduced (Figure 13(a)) and there is no loss of permeability. This additive has since been tested in the field and has contributed substantially to the success of the field pilot.

CONCLUDING REMARKS

In North America, production departments are increasingly using reservoir models to design field projects and where necessary, are obtaining the basic data they need from, what may be termed, technical service laboratories. Where the recovery processes are well understood and where the models incorporate the essential mechanisms, good results are obtained. Where difficulties occur is when these same models are used to design not well understood processes in complex reservoirs and where the designers are using the models as a "black box" without taking a critical look at the predictions or the areas of uncertainty. With the aid of modern graphics these models produce such convincing pictures that engineers and managers alike are seduced into thinking they are looking at reality.

In this paper the authors have shown that there is a role for a central engineering research group whether that be in a large company or in a country. If that group, however, is to be effective it must continue to direct its efforts towards those areas where technology does not exist or is not well understood. It must continue to be innovative in developing the technology to recover oil from difficult or not well understood situations. It must continue to probe and explore and understand what the mechanisms are that are operating in these situations, both at a laboratory and at a field scale and it must be able to build and understand the mathematical tools that will enable prediction on a field scale, including the strengths and limitations of these tools. In addition, it must be knowledgeable of and continue to address the ongoing technical field problems which occur from time-to-time in oil field recovery operations or when innovative approaches are being applied in the field.

We have found in AOSTRA that, firstly, it is important when applying new technology or when applying existing technology to a new area that well planned and engineered pilots are conducted prior to field application. Invariably, we have found that when we try to short circuit the development process, we have run into difficulties which are costly both in time and money.

Secondly, we have found that the best field tests are those that have been planned, engineered and executed under the direction of a dedicated research and development group whose team has included an ongoing reservoir engineering research effort in the laboratory and in the prediction, design and analysis of the results of the field test.

With increasingly more difficult and more costly oil being recovered, a reservoir engineering research group is as vital today as at anytime in the historical exploitation of our hydrocarbon resources. If it is to be effective, however, it must avoid becoming a service group or using its physical laboratory resources for routine field predictions but rather must continue to be innovative in meeting real field needs and become an active partner in the ongoing development of new recovery technology and its application to new geological or petrophysical situations.

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Figure 1
Interrelationship Between Scaled and Unscaled Models for Prediction of Field Performance

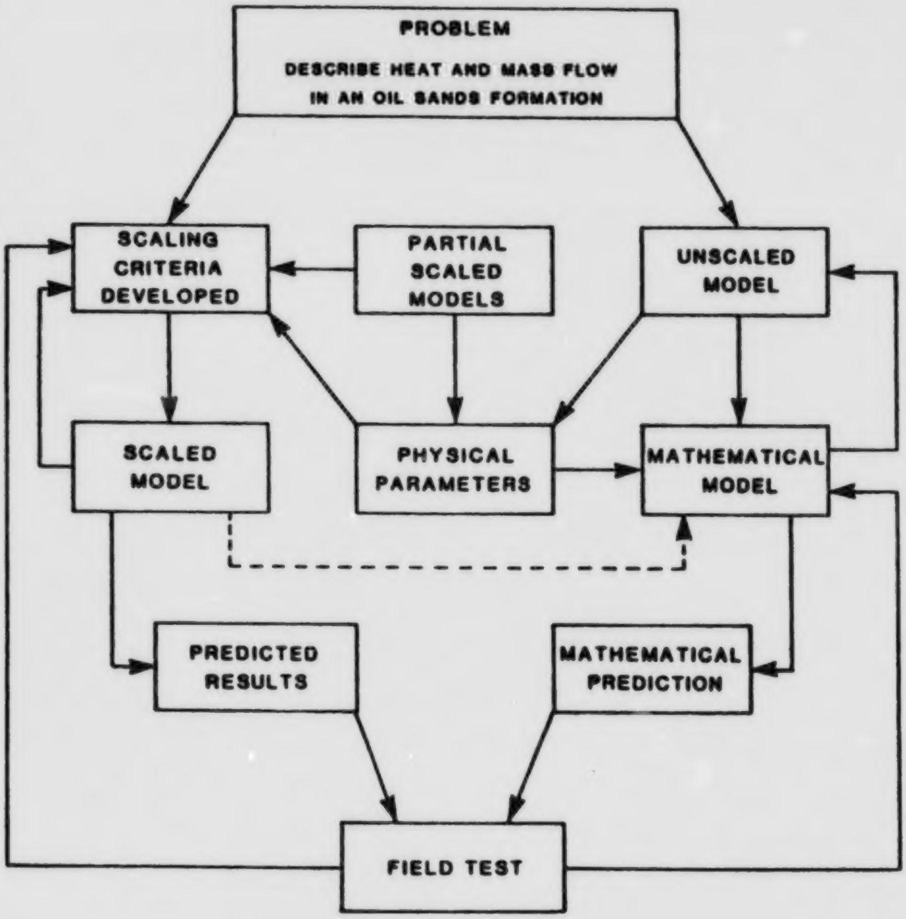

PROBLEM
DESCRIBE HEAT AND MASS FLOW IN AN OIL SANDS FORMATION
SCALING CRITERIA DEVELOPED
PARTIAL SCALED MODELS
UNSCALED MODEL
SCALED MODEL
PHYSICAL PARAMETERS
MATHEMATICAL MODEL
PREDICTED RESULTS
MATHEMATICAL PREDICTION
FIELD TEST

Figure 2
Pattern Layout for Texaco Athabasca Field Pilot Project

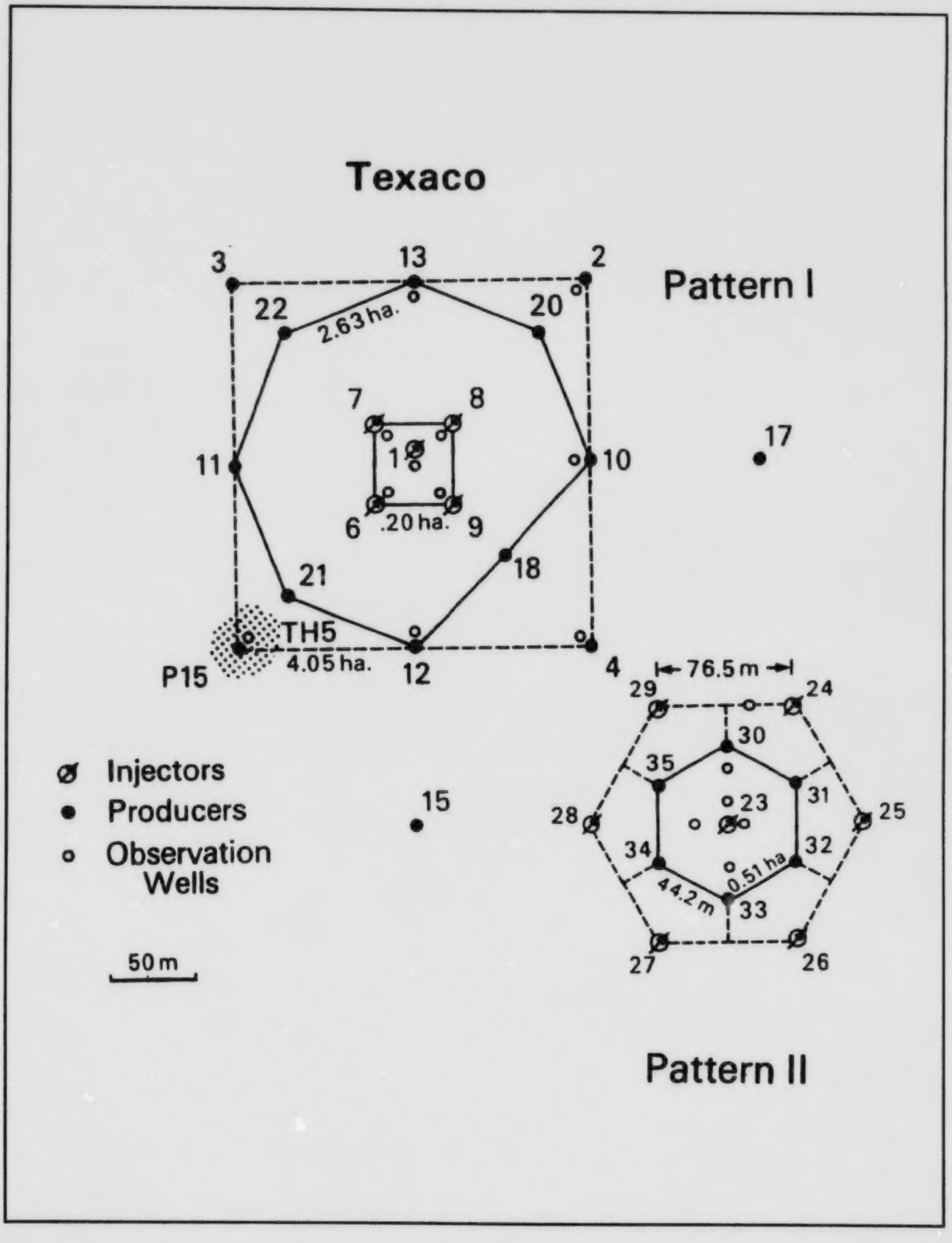

Texaco
Pattern I
3
13
2
22
20
2.63 ha.
7
8
1
17
11
10
6
.20 ha.
9
21
18
TH5
P15
4.05 ha.
12
4
76.5 m
29
24
30
35
31
23
28
25
34
32
0.51 ha
44.2 m
33
27
26
15
Injectors
Producers
Observation Wells
50 m
Pattern II

Figure 3
Example Comparison Between Steam With and Without Naphtha During a Cyclic Pressure Process (45 cm Physical Simulator Test Data)

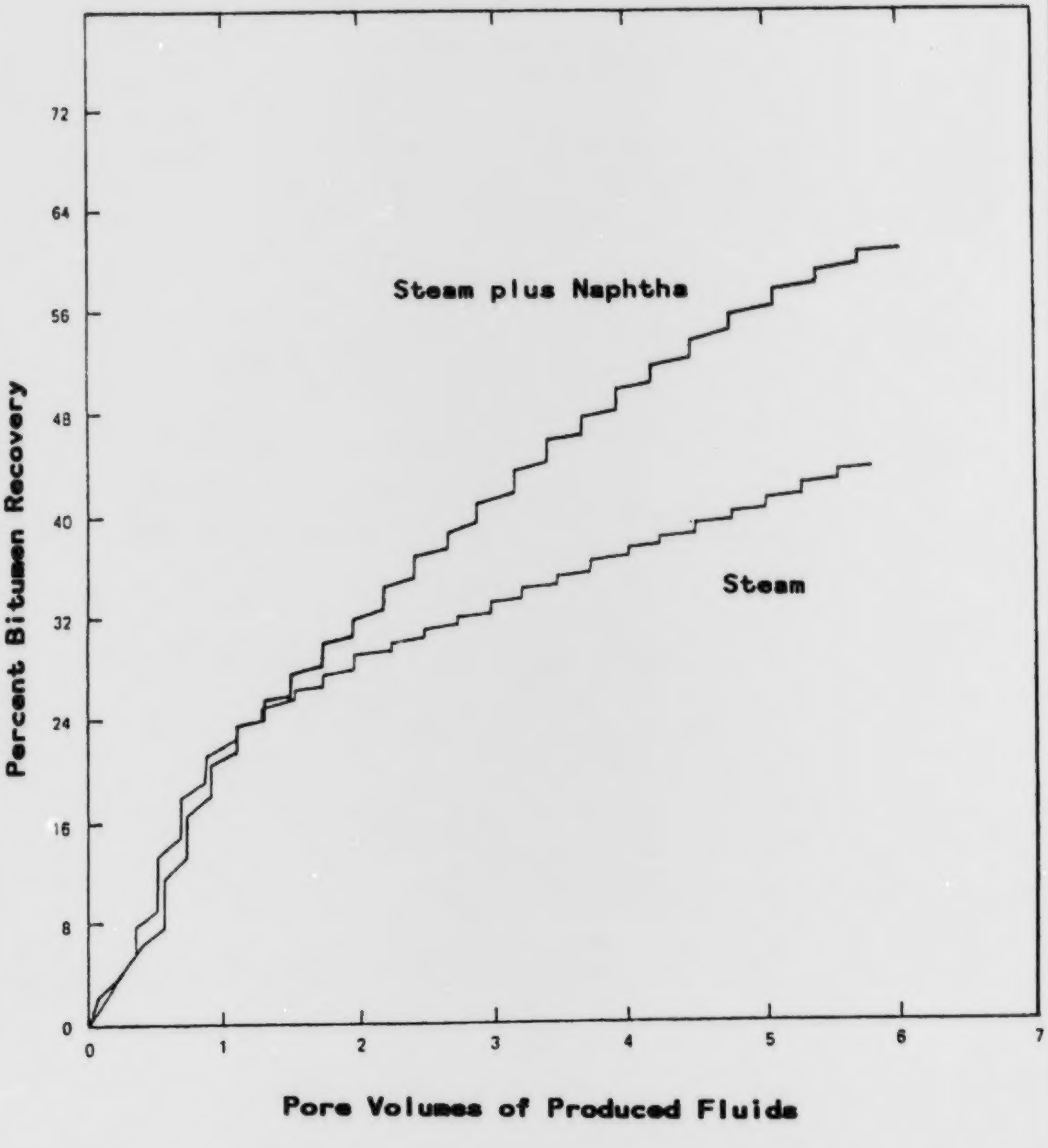


Figure 4
Athabasca Pilot Project Pattern II Recovery Curve

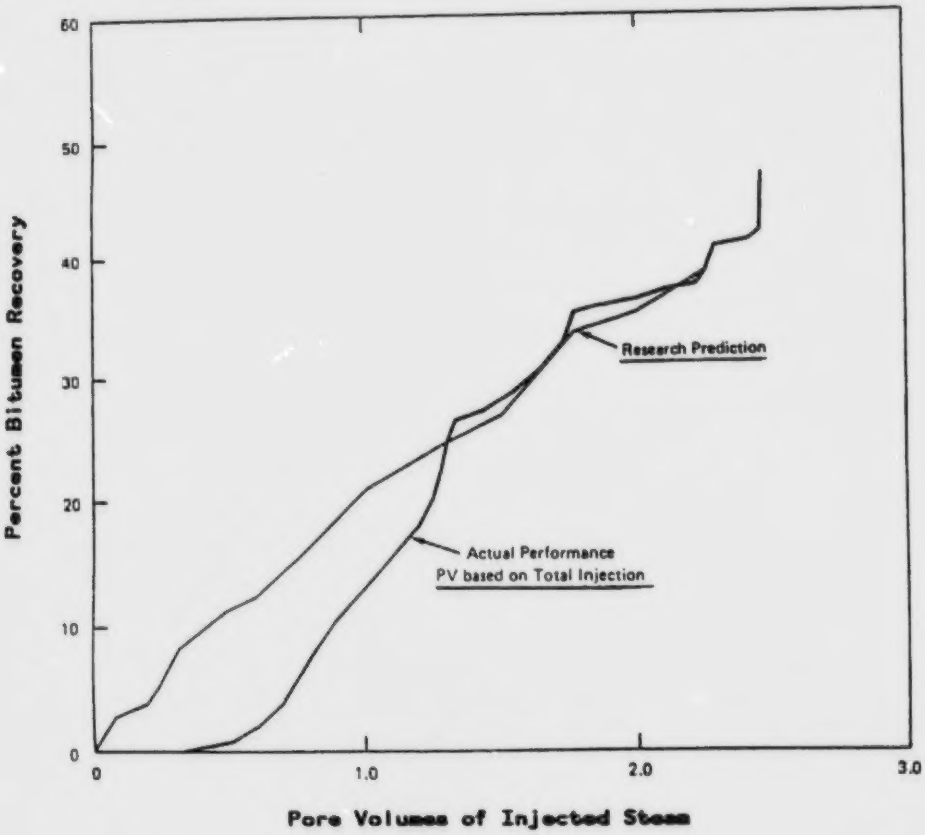


Figure 5
Comparison of Bitumen Recovery From Cyclic and Soaking Processes (45 cm Physical Simulator Test Data)

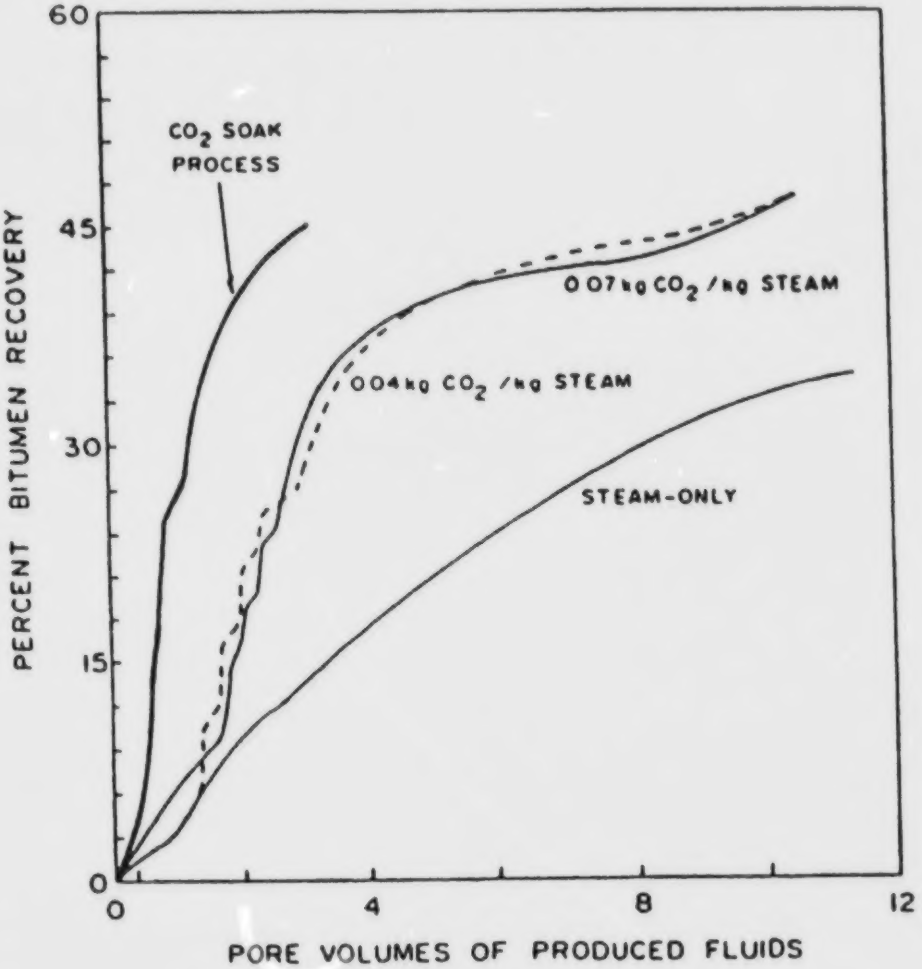


Figure 6
Comparison of Recovery Curves for Steam, Steam-Naphtha and Steam-Naphtha-CO_2 (45 cm Physical Simulator Test Data)

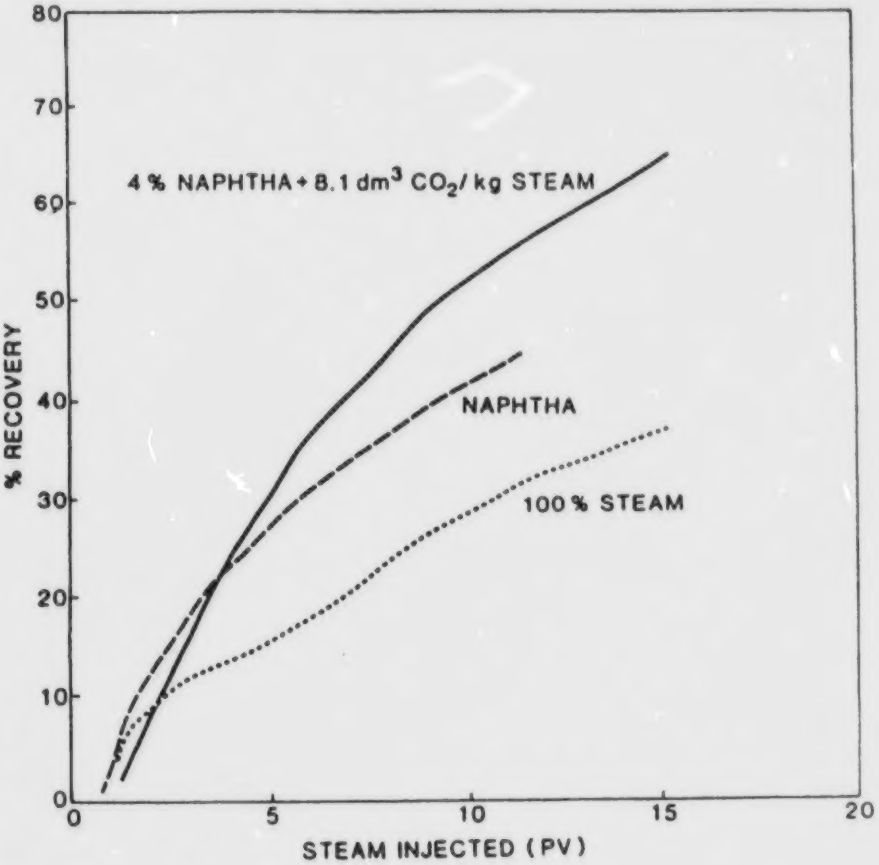


Figure 7
Single Beam X-Ray Scanner

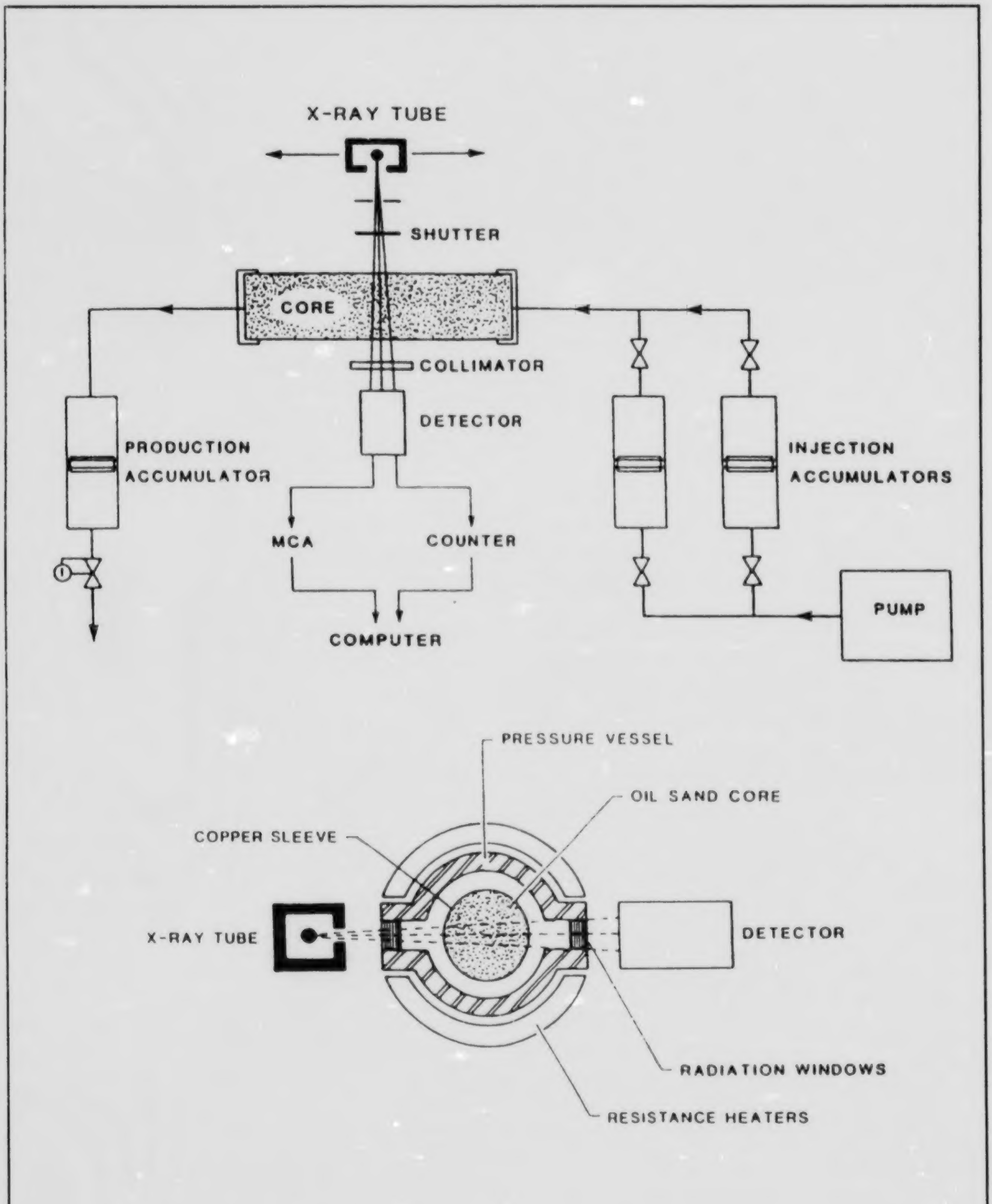

X-RAY TUBE
SHUTTER
CORE
COLLIMATOR
DETECTOR
PRODUCTION ACCUMULATOR
INJECTION ACCUMULATORS
MCA
COUNTER
COMPUTER
PUMP
PRESSURE VESSEL
OIL SAND CORE
COPPER SLEEVE
X-RAY TUBE
DETECTOR
RADIATION WINDOWS
RESISTANCE HEATERS

Figure 8
Xeroradiography Core Imaging Apparatus

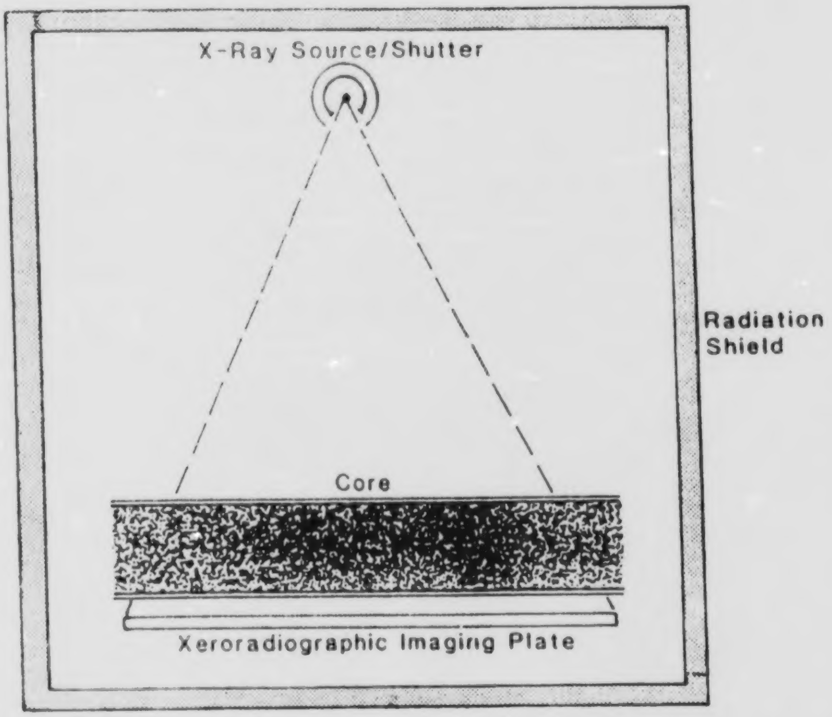

X-Ray Source/Shutter
Radiation Shield
Core
Xeroradiographic Imaging Plate

Figure 9
Schematic of X-Ray Computed Tomography Scanner Modified for High Temperature/Pressure Corefloods

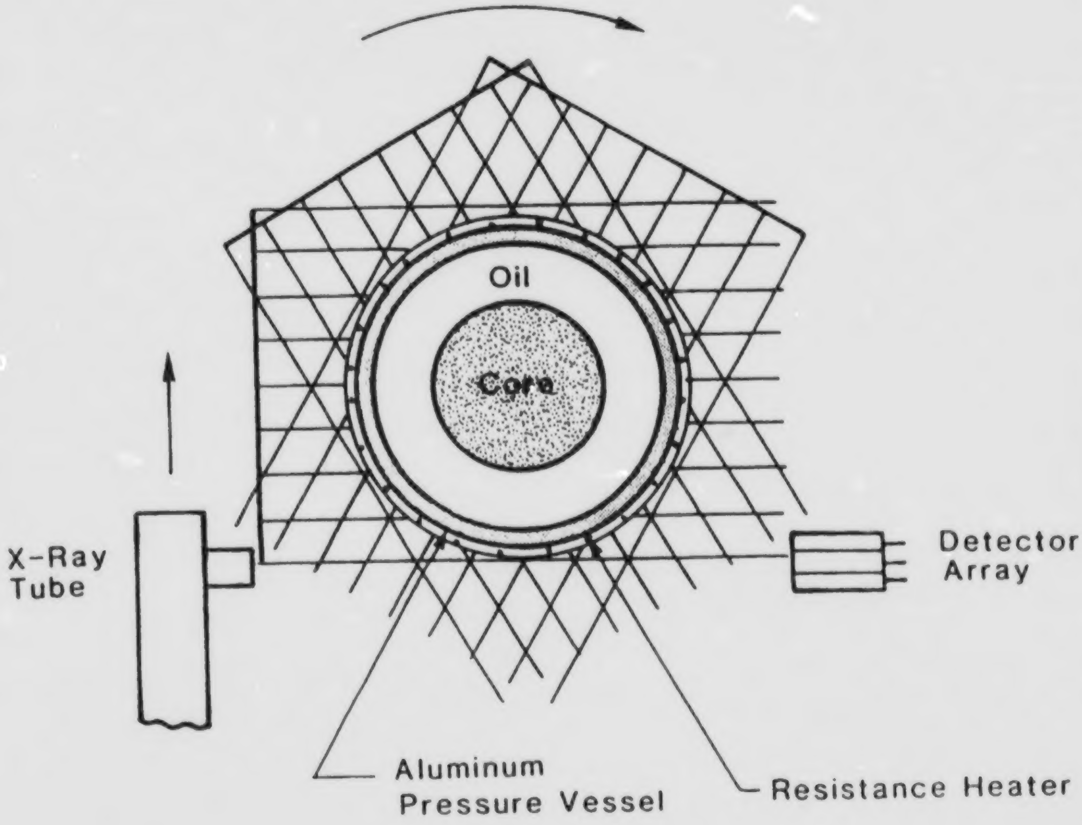
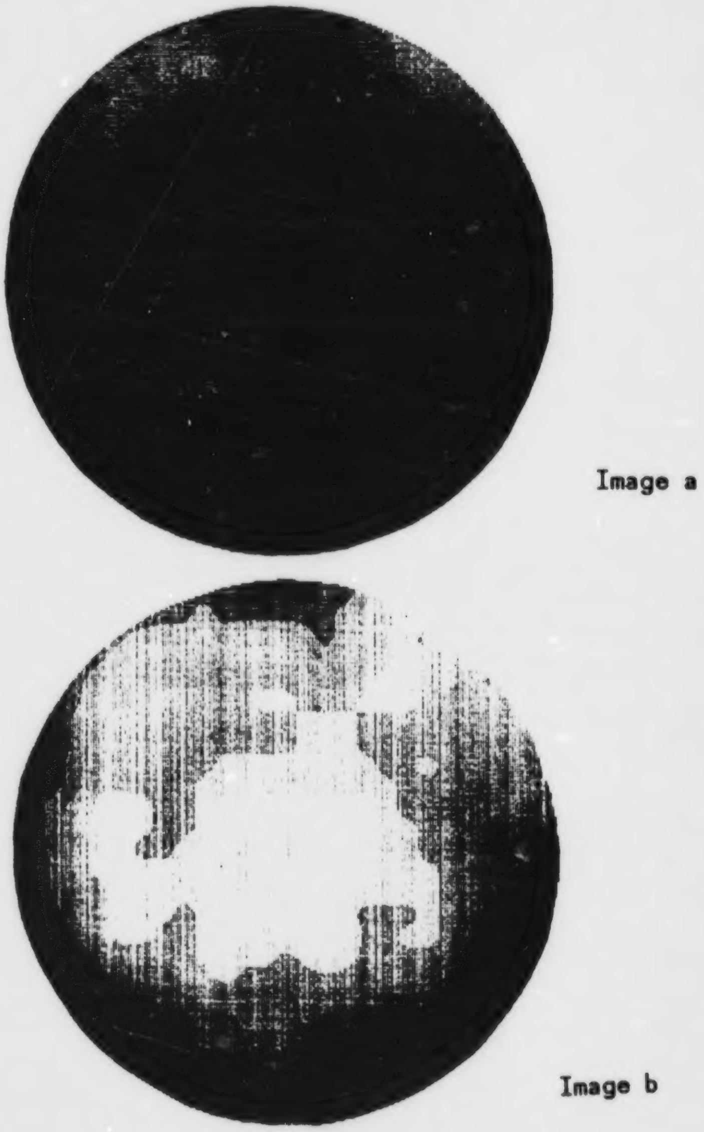

Oil
Core
X-Ray Tube
Detector Array
Aluminum Pressure Vessel
Resistance Heater

Figure 10
Computed Tomography Cross-Sectional Slices Showing Bitumen Saturation During Water Flood



Gray scale ranges from dark (high bitumen) to light (lower bitumen); 125°C and 3 MPa pore pressure; Image a after 0.25 pore volumes injected water, mean saturation approximately 0.7; Image b after 3.0 pore volumes of water, mean saturation approximately 0.45.

Figure 11
High Pressure-Temperature Test Cell for Measuring the Effectiveness of a Solids Control System

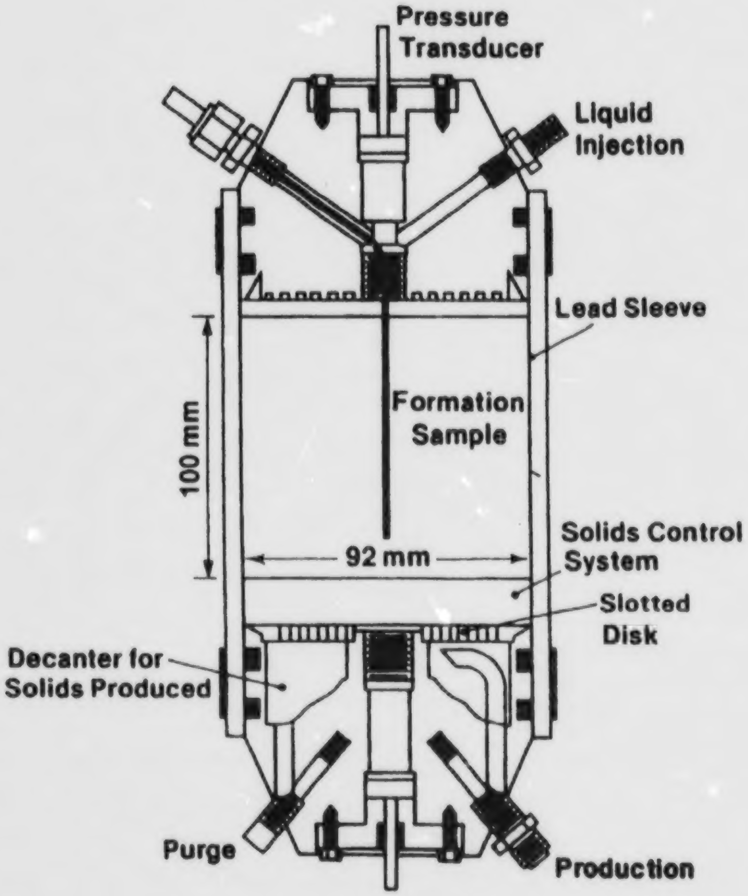

Pressure Transducer
Liquid Injection
Lead Sleeve
100 mm
Formation Sample
92 mm
Solids Control System
Slotted Disk
Decanter for Solids Produced
Purge
Production

Figure 12
Piping and Environmental Control Arrangement for High Pressure-Temperature Test Cell

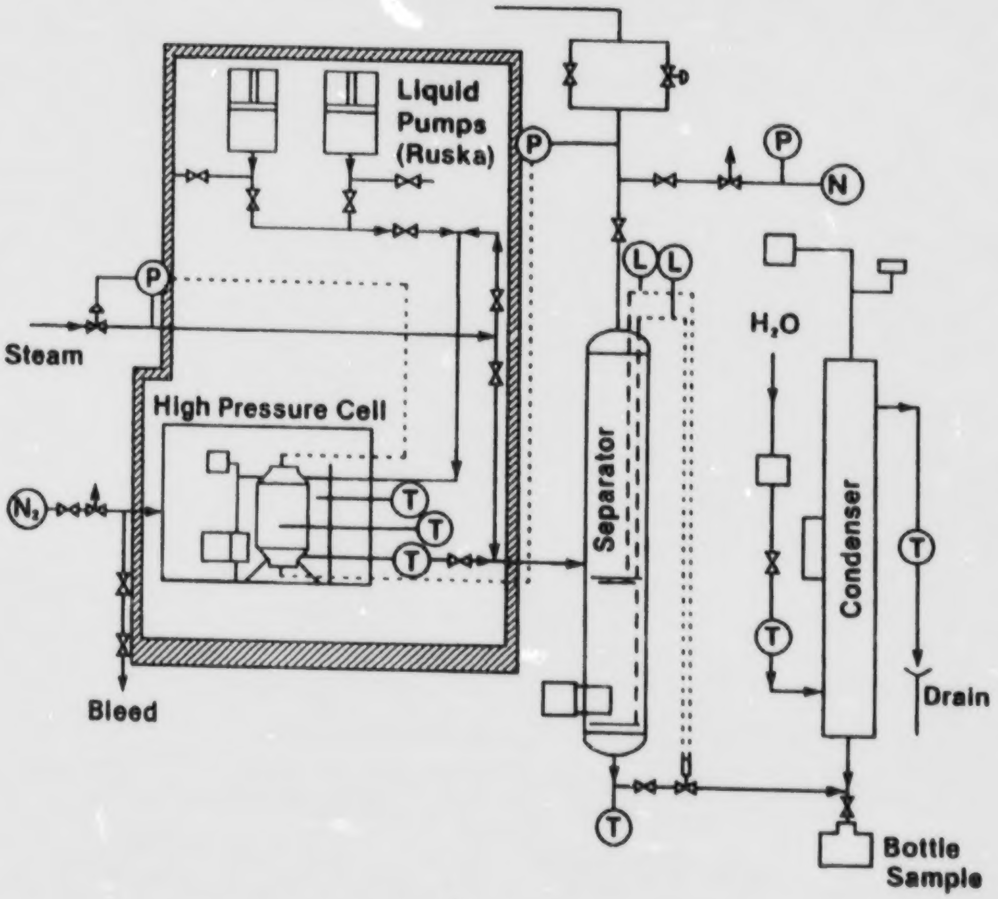

Liquid
Pumps
(Ruska)
P
P
N
L
L
H_2O
Steam
P
High Pressure Cell
N_2
T
T
T
Separator
Condenser
T
T
Drain
Bleed
T
Bottle
Sample

Figure 13 (a)
X-Ray Diffraction Test Data

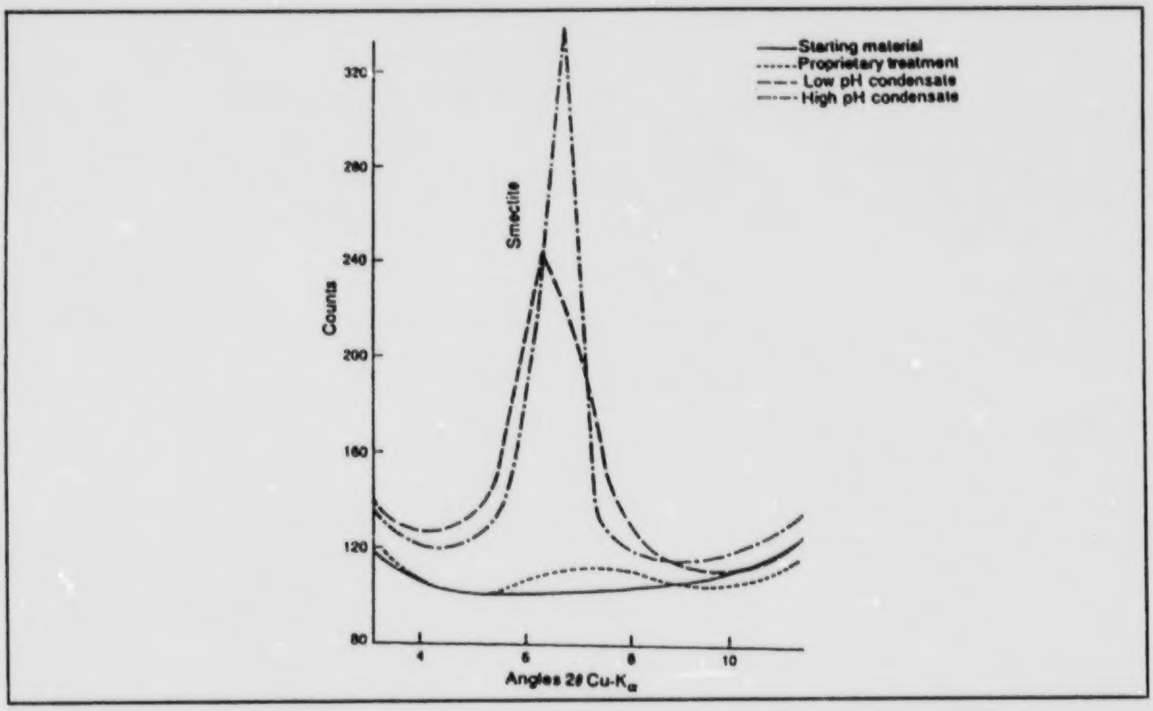
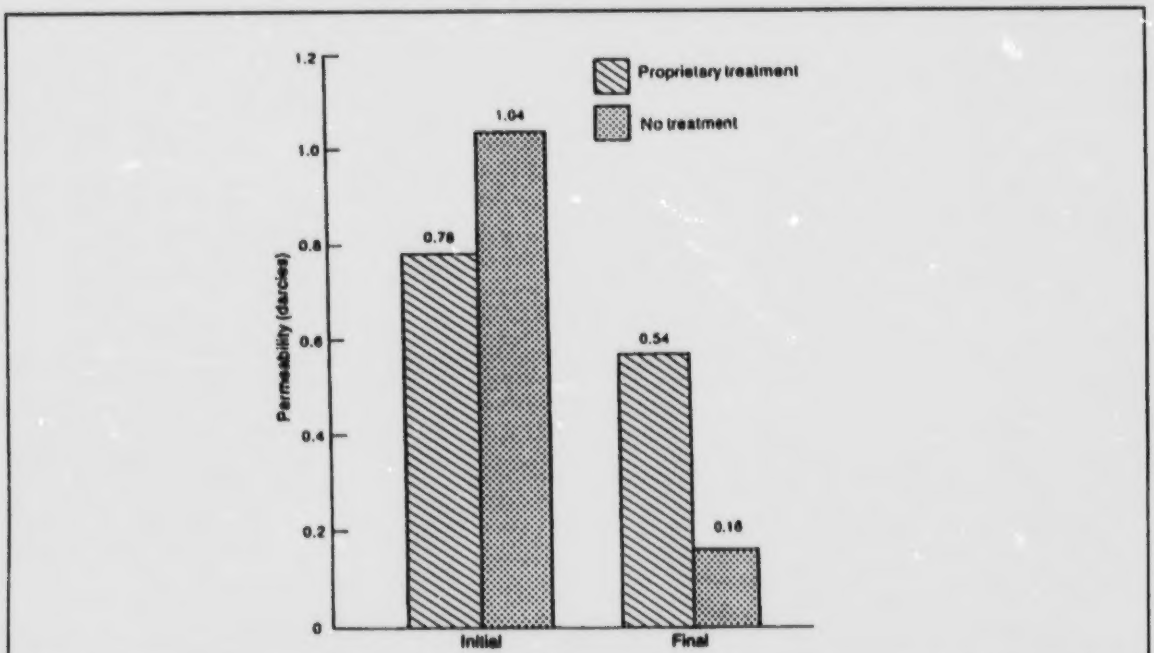


Figure 13 (b)
Permeability of Core Material Before and After Flooding



8

SIMULATION OF STEAM DRIVE IN A HETEROGENEOUS RESERVOIR

Zhai Jianhua

Shang Huanmin
RIPED, Beijing

ABSTRACT

A numerical simulation was performed to study the feasibility of steam drive and to improve the oil recovery process for a heterogeneous reservoir, pilot 9-3 in Karamay field. The formation cross-section shows that the formation is a mud-sand combination and the reservoir is an intercalated bed development. The occurrence of heterogeneity is quite pronounced in both the areal and interlayers. The effect of heterogeneity on steam drive was carefully studied and the results indicate that the effect of heterogeneity to steam drive of the pilot is significant. In order to improve oil recovery, the steam stimulation must be used to assist the steam drive and the steam must be injected layer by layer.

INTRODUCTION

The pilot is located in the south district 9 of Karamay heavy oil field. It consists of nine patterns of inverted 5-spot wells. The well spacing is 100 meters. As shown in Figure 1, the formation being flooded is Jurassii Qigu group sand G22 which is a fluvial river bed sediment. The sediment thickness is 47.8 meters. The sand body is a classic sedimentary rock with gravel and medium coarse sand. The oil reserve is very good. The porosity, permeability, and oil saturation are high. The intercalated bed in G22 is fairly well developed and can be divided into two layers, G2-1 and G2-2, (abbreviated G21 and G22). The oil reserve of G21 is better than that of G22 and shows not only a stronger formation heterogeneity but also a stronger areal heterogeneity due to the sedimentary condition.

Pilot 9-1, adjacent to pilot 9-3, is being conducted as a full scale steam injection development and has achieved great success. We are able to match the production history and to simulate the performance of steam injection for pilot 9-1 very well. The results give us great confidence in our ability to simulate. In addition, we have examined the steam drive results from District 9 of Karamay; it indicates the significant effect of areal heterogeneity.

Based upon our previous experience, this paper presents the simulation results for pilot 9-3 and the detailed study of the effects of heterogeneity to steam drive. By referring to the experience at home and abroad, we put forward several problems which one should be made aware of in the practical steam drive process.

RESERVOIR MODEL

A 3-dimensional and 3-phase black oil simulator was used in this study and the model was simulated using on IBM PC/XT.

According to the pilot 9-3 reservoir characteristics, a 3-D heterogeneous model was set up, as shown in Figure 2. Wells 1 and 3 are production wells and Wells 2 and 4 are injection wells. Table 1 gives the formation thickness, porosity, permeability, and oil saturation. It shows a strong areal and interlayer heterogeneity, especially the permeability contrast between two layers. Under this condition, it causes some difficulty for steam drive, such as low sweep efficiency and low oil recovery for G22 which are the problems to be studied in our simulation.

As shown in Figure 2, the model consists of a 6*6*3 grid blocks. The X and Y coordinates are 0, 10, 30, 50, 70, 90, and 100 meters respectively. The Z-coordinates are 192, 198, 201, and 205 meters with a 3 meter mud-rock intercalated bed between 198 to 201 meters. To simulate the effects of 6 and 9 meters intercalated to steam drive, another grid system of 6*6*4 was used. The difference is that the intercalated bed is subdivided into two layers. Because the sand of G21 and G22 are thin only the lower half of sand G21 is injected. From our previous work (1), the steam override in sand is not serious, hence a one layer grid is used for the two sands respectively.

OPTIMAL STEAM INJECTION RATE

First, three cycles of steam stimulation (huff and puff) for Wells 1 to 4 were simulated. Table 2 gives the data used. The results indicate that for the total four wells, the steam injected and produced are 13,000 tons and 9136 tons respectively. The accumulated OSR is 0.7. The oil recovery is 13.2 %OOIP and the 3-cycle production time is one year. The steam stimulation heated the formation and it provided a better condition for steam drive.

Continuing with the steam stimulation, the steam drive simulation was performed under different steam injection conditions. The three injection rates are 28, 32 and 36 tons/day for injection Wells 2 and 4, and steam quality at bottom hole is 60 %. The simulation results are shown in Table 3. The production time is limited by an OSR of less than 0.15. The net oil production is defined as the oil produced minus the sum of the fuel oil (steam fuel ratio 12 tons/day) and the other cost (0.5 tons/day-well). Table 3 shows that the best injection rate is 32 tons/day, since the OSR and oil recovery are better than the other two injection rate, especially the net oil production. From our analysis, two factors contribute to this. One is that the areal heterogeneity makes the liquid production concentrate in Well 3 as shown in Figure 3. It is equivalent to two injectors. Well 3 bears the steam injection rate greater than 32 tons/day. The other factor is that the formation heterogeneity makes the steam flow toward G21 (average thickness only about 6 meters).

Hence a greater steam injection rate could cause a serious steam fingering and a small area sweep. In addition, the pump capacity of the pilot (less than 80 tons/day) is impossible to inject at a higher rate. To conclude, a reasonable injection rate should be used for a heterogeneous reservoir.

IMPROVING THE AREAL SWEEP EFFICIENCY

Table 3 indicates that the maximum oil recovery was obtained at only 21.8 %OOIP. Figure 4 shows that the steam zone areal distribution is at G21. It also shows that one of the causes of low oil recovery is that a very large zone around production Well 1 was not swept by the steam.

In order to improve this situation, a 750 day steam stimulation was employed for the production well. The amount of steam injected was 3200 tons at 60% quality. When Well 1 was injected, the injection rate was reduced at Wells 2 and 4 to prevent higher reservoir pressure. As shown in Figure 3, Well 1 oil production increased after steam stimulation and the current OSR improved as well; however Well 3 production decreased. The simulation results at 1600 days is shown below:

Cum. Production	. Recovery	OSR	Net Oil Production
Cum.	Cum.		
(*1e4 tons)	(%OOIP)		(*1E4 tons)
1.541	22.3	0.159	0.424

Comparing this table to Table 3, the results show that oil recovery, OSR, and net oil production increased somewhat after the steam stimulation. Figure 5 shows the temperature profile of G22 at 1600 days. The comparison of these two figures 6 and 7, shows that the heat transfer of G22 was improved due to the steam stimulation of Well 1.

IMPROVED OIL RECOVERY OF G22 LAYER

Figure 7 shows that the steam zone of G22 layer is still very small and it is not flooded by steam after 1600 days. The oil recovery is also low. But at the same time, G21 has steam breakthrough already and the pressure drop to around 4 atm; i.e., low oil production and high steam production. Therefore G21 must be shut-in, in order to flood G22. Although the thickness of G22 is only about 4 meters, because of the heat transfer from G21, the average temperature of G22 increases from 24xC to 69xC. Under this condition, the oil viscosity decreases from 2330 cp to 155 cp which improves oil mobility greatly. The strategy employed was that at 1600 days, G21 formation was shut-in; in the meantime, Well 1 was converted from production to injection with injection rate 32 tons/day to G22 formation. Wells 2 to 4 were used as production wells. Because the formation temperature around Wells 2 and 4 was higher due to the initial injection period, it was useful for G22 development. The formation temperature around Well 3 was also higher due to its lower permeability, hence it was not suitable for steam injection and it was still a production well. At this time, it is important to control the injection pressure, in order to avoid the steam breaking into a higher permeability layer. Figure 8 shows the production history of Wells 2 to 4. From the current OSR curve, a better economic efficiency was obtained which reflected that the heat transfer could make steam injection for thin formation an economical success.

Figure 9 shows that oil recovery and OSR as a function of time. After 5.8 years, the cumulative OSR was 0.176 and the cumulative oil recovery was 29.4 %OOIP. Following steam drive, the steam stimulation was performed, and the cummulative OSR and oil recovery were 0.23 and 42.6 %OOIP respectively.

THE EFFECT OF INTERCALATED BED THICKNESS TO STEAM DRIVE

There was a 3 meter thick intercalated bed between G21 and G22 in the previously used reservoir models. In the pilot 9-3 there are some well units with intercalated bed thicknesses greater than 3 meters. To study the effect of intercalated bed thickness to steam drive, the steam drive performance of 6 and 9 meter intercalated beds were also modeled. The data used are the same as the previous model shown in Table 2. Figure 10 shows the linear relationship of the cumulative OSR and intercalated bed thickness.

When intercalated bed thickness was 9 meters, the cumulative OSR was 0.163 and oil recovery was 27.1 %OOIP of which 21.4 % was from G22 after G21 was shut-in. The cumulative OSR was 0.159 which was comparable to the Figure 9 results at 1600 days. This reflected that the intercalated bed thickness was greater than 10 meters (effective formation thickness/total formation thickness), and that the heat transfer decreased between intercalated layers; hence it could not benefit from the steam injection. When the intercalated bed thickness varies very much, one has to be careful in selecting the injection layer.

CONCLUSION

- ☐ *1. The optimal injection rate is 32 tons/day.*
- ☐ *2. Conducting the steam stimulation for the production wells which have poor performance to steam drive can improve the areal sweep efficiency.*
- ☐ *3. Conducting the steam drive alone for the layer which has poor heat transfer can improve the oil recovery of that layer.*
- ☐ *4. When the intercalated bed thickness is less than 10 meters (effective formation thickness/total formation thickness 0.5), one could use the effect of heat transfer from the more permeable layer to develop the poor layer.*

ACKNOWLEDGMENTS

We acknowledge Mr. Luo Meixian and his colleagues at the Institute of Xinjiang Petroleum Administrative Bureau for providing good geological data.

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Table 1
Reservoir Model Parameters

Well No.		1	2	3	4
Porosity	G21	0.355	0.33	0.37	0.29
	G22	0.3	0.295	0.27	0.31
Permeability, md	G21	9400	4961	12300	2720
	G22	1712	1416	731	2620
Oil Saturation	G21	0.58	0.57	0.58	0.605
	G22	0.59	0.58	0.58	0.58
Net thickness, m	G21	5.0	8.0	7.0	4.0
	G22	5.0	3.0	5.0	3.0

Table 2
Input Data

Depth, m	200
Initial pressure, at	22
Initial temperature, °C	20
Oil viscosity, cp, at 20°C	4000
at 90°C	60
Oil density, g/cm^3	0.92
Pore compressibility, 1/at	1.5×10^{-3}
Reservoir thermal conductivity, W/m°C	2.1
Overburden thermal conductivity, W/m°C	2.1
Irreducible water saturation (Swir)	0.42
Residual oil saturation to water (Sorw) at 20°C	0.3
at 200°C	0.12
Residual oil saturation to steam (Sorg)	0.1

Relative Permeability Expressions[5]:

$$Krw=0.15\times\left[\frac{Sw-0.42}{0.58-Sorw}\right]^{2.4}, \quad Krow=0.8\times\left[\frac{1-Sorw\ \ Sw}{0.58-Sorw}\right]^{2.0}$$

$$Krog=0.8\times\left[\frac{0.48-Sg}{0.48}\right]^{2.1}, \quad Krg=0.2\times\left[\frac{Sg-0.02}{0.46}\right]^{1.4}$$

Table 3
Optimal Steam Rate

Steam Rate (T/d)	Time (D)	Cum. oil production $(10^4 T)$	Oil recovery % OOIP	Cum. OSR	Net oil production $(10^4 T)$
28	1650	1.411	20.4	0.153	0.313
32	1500	1.506	21.8	0.157	0.406
36	1300	1.378	20.0	0.147	0.337

Figure 1
Lith Column

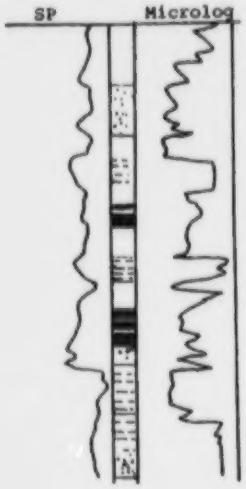


Figure 2
Reservoir Model

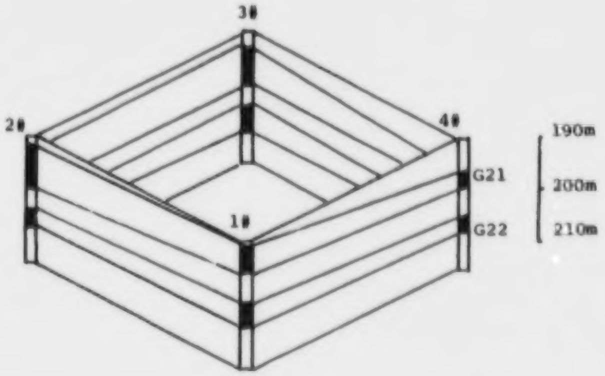

3#
2#
4#
1#
G21
G22
190m
200m
210m

Figure 3
Steam Drive Performance

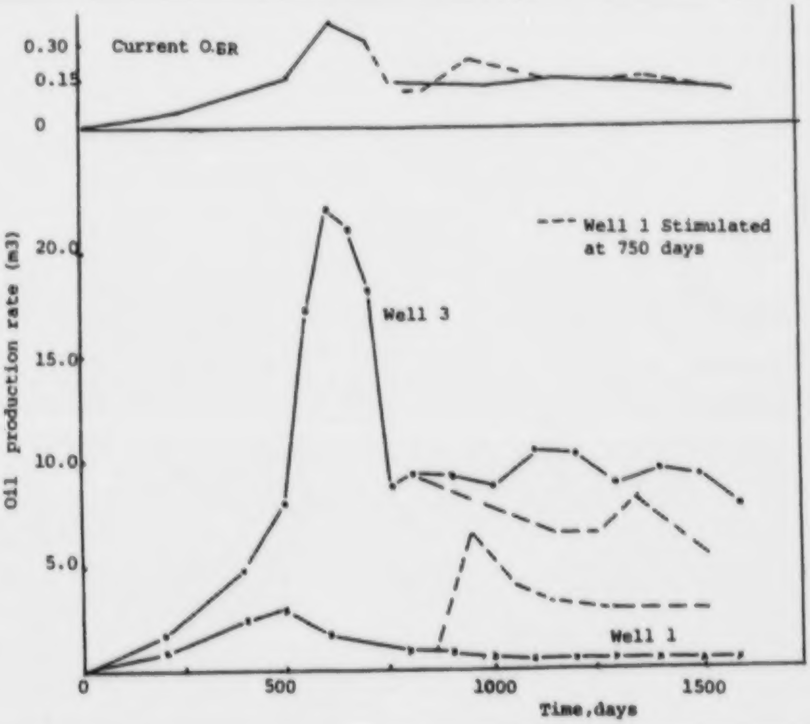


Figure 4
Temperature Contours in G21

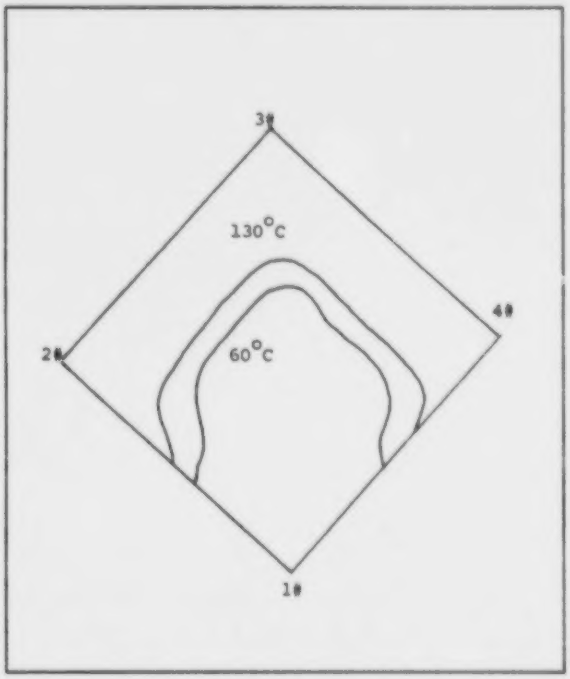

3#
130°C
4#
2#
60°C
1#

Figure 5
Temperature Contours in G21 (1# Stimulated)

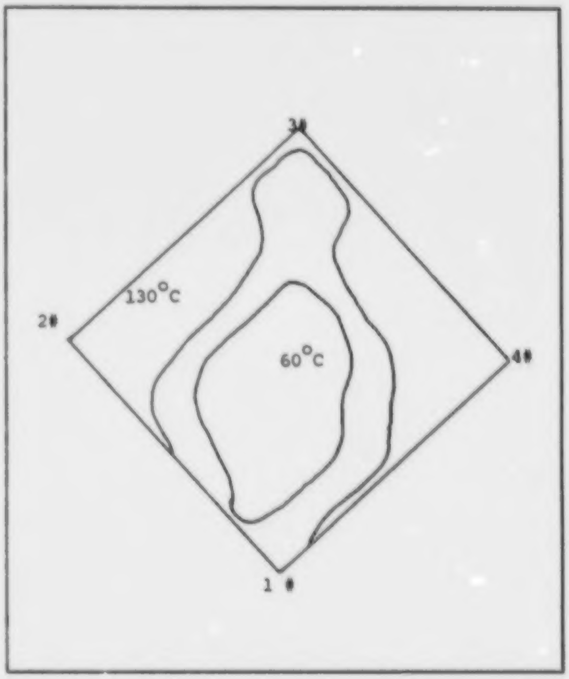

3#
130°C
2#
60°C
4#
1 #

Figure 6
Temperature Contours in G22

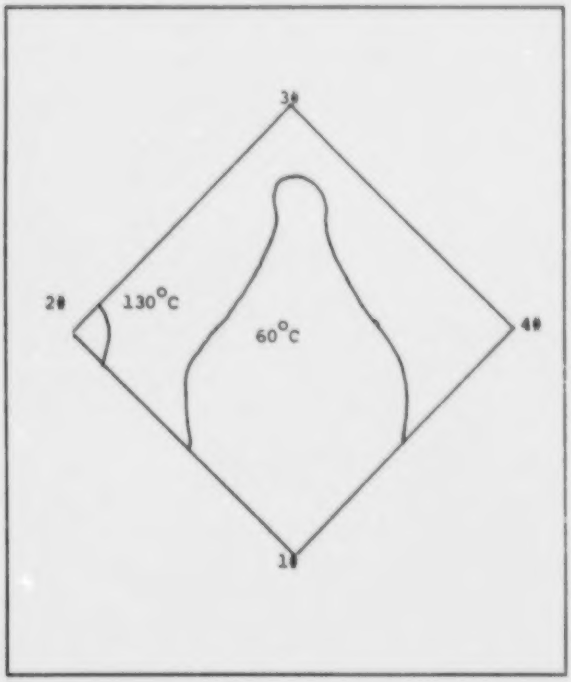

3#
2#
130°C
60°C
4#
1#

Figure 7
Temperature Contours in G22 (1# Stimulated)

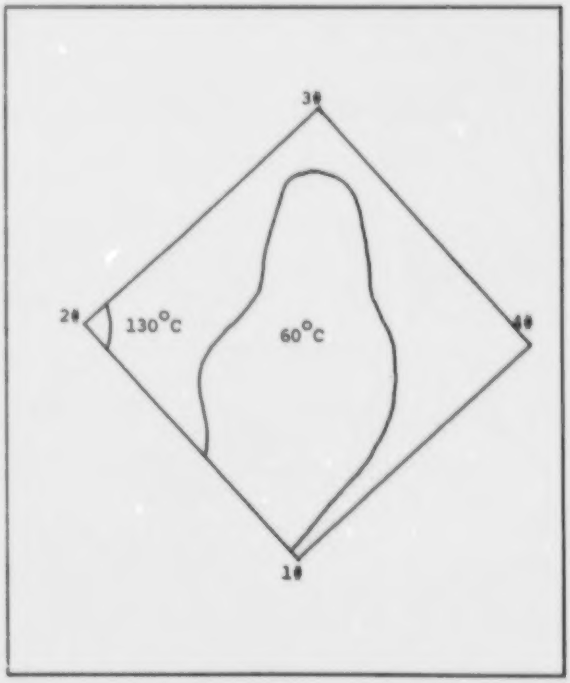

3#
2#
130°C
60°C
4#
1#

Figure 8
Steam Drive Performance (G22 Only)

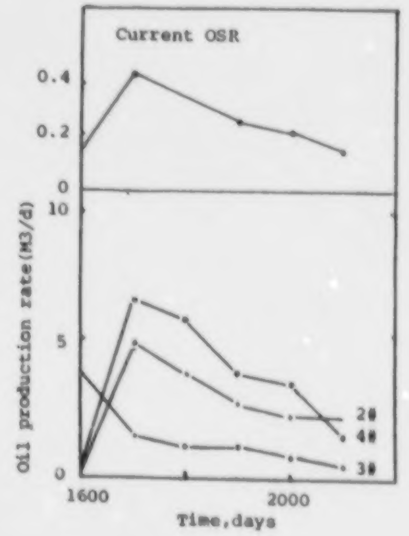


Figure 10
Effect of Intercalated Bed

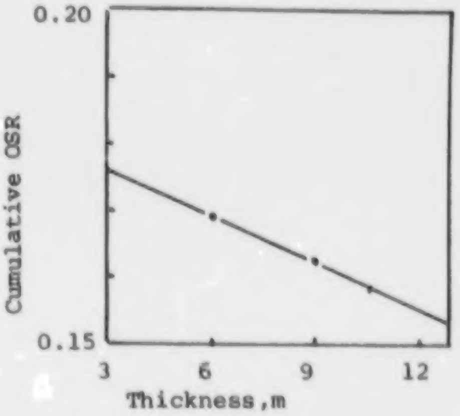
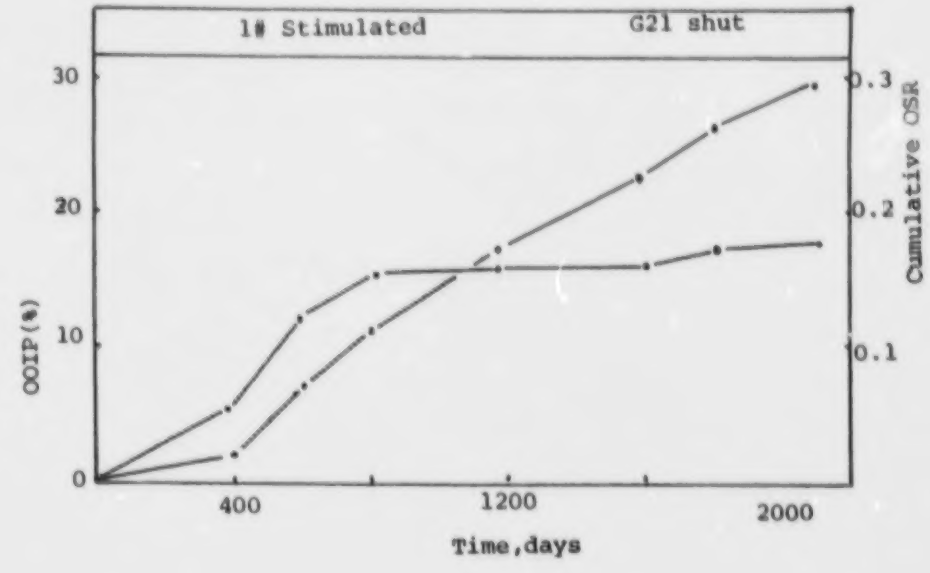


Figure 9
Oil Recovery & Cum. OSR of Steam Drive



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SCALING LAWS FOR ENHANCED OIL RECOVERY EXPERIMENTS

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ABSTRACT

Laboratory experiments of enhanced oil recovery (EOR) methods are of great value in understanding the mechanism of a given EOR process. Use of advanced mathematical simulators only reinforced the need for carefully planned laboratory experiments. This paper views selected EOR methods from laboratory experimentation perspective. The methods discussed are: miscible displacement, chemical flooding, emulsion flooding, foam injection, immiscible carbon dioxide flooding, steam injection, solvent leaching of bitumen, and combustion. A notable feature of this paper is a compilation of the scaling groups for all these processes. Many of these scaling criteria have not been published before. In several instances, alternative sets of groups are given for a process, pointing out the problem of imperfect scaling. Choice of the proper set of scaling criteria for a given process is important, and general guidelines are offered in this regard. Also, areas that have been largely neglected are pointed out.

INTRODUCTION

Most of the currently used EOR techniques involve steamflooding, combustion, thermal-miscible methods, carbon dioxide, polymer, emulsion and foam flooding, and combination of these methods. Other methods include development of a cold-propped fracture,[1,2] use of explosions, solvent stimulation, etc.

Physical models of a particular recovery process as applied to an element of an oil-bearing formation can be scaled, partially scaled or unscaled. A scaled model is designed on the basis of the principle of similarity, first enunciated by Newton for systems of solid particles in motion. Such a model is characterized by the same ratios of dimensions, forces, velocities, temperature differences and concentration differences as those occurring in the prototype. The Principle of Similarity has been discussed by many authors, and will not be discussed here. (See e.g. Johnstone and Thring[3]).

Scaled models are highly desirable as the results may be used directly in field predictions, however, in view of the scaling problems involved, they are seldom attainable. In such cases, a partially scaled model in which some of the scaling criteria are relaxed may be adequate. The important question one must answer is: do the relaxed scaling criteria introduce appreciable errors in the results? The answer may come from experiments in two similar, but different sized models, or one may resort to the mathematical simulation of the partially scaled model to gain insight into the interactions of the neglected scaling relationships.

A different approach is to forgo physical models altogether and to rely entirely on mathematical representation to predict field or laboratory results. The physical model (normally unscaled or partially scaled) may then be used to validate the predictions of the mathematical representation and/or to obtain parameters for use in the mathematical representation.

In this paper, a review of scaling criteria is given for different EOR processes. The problem of partial scaling is then considered and observations made on conditions under which certain scaling criteria may be relaxed.

In this paper different scale-up procedures are not discussed. Interested readers may refer to reviews by Farouq Ali et al.[4] and Farouq Ali and Redford[5].

SCALING CRITERIA FOR THERMAL METHODS

Thermal methods are often used for exploiting reservoirs with oil sands (often called "tar sands") or heavy oil reservoirs. In some instances, thermal methods are applied in combination with other recovery techniques that use additives, such as, caustic, foam, polymers, surfactants, solvents, gases, etc. Thermal recovery methods may be classified under the followings.

Hot Water Injection

Geertsma et al.[6] developed the scaling criteria for a two-component, two-phase hot waterflood process. They derived the scaling groups using both inspectional and dimensional analyses. The scaling groups are reported in Table 1. Even for this relatively simple process, it was shown that it is virtually impossible to satisfy all the scaling groups. In this context, the group $l/\sqrt{k}$ may be cited as an example, where and k are the model length and permeability respectively. Whenever a group cannot be satisfied, it has been found useful to study the range over which this group may be neglected. For instance, Abbasov and Melikov[7] investigated the dependence of oil recovery by gas drive as a function of $l/\sqrt{k}$, and reported that above a value of 26.5×10^{4}, recovery was practically independent of this group, even though for a lower value of k, recovery increased almost linearly with a decrease in $l/\sqrt{k}$.

It can be shown that even without considering $l/\sqrt{k}$, it is almost impossible to satisfy all the groups for this process. Three scaling options are evident for this set of scaling groups.

Approach 1: Same fluids, different porous media, different pressure drop, geometric similarity.

This approach scales viscous and gravitational forces properly. However, a different porous medium is required to have a different Δp in the model and the prototype. This leads to a questionable scaling of the irreducible saturations and also relative permeabilities are not scaled. Also, the capillary forces are not scaled properly. The implication of these scaling criteria for a model reduced in length by a scaling factor of 'a' are

i) ϕ, S_{oi}, T_b/T_i must be the same

ii) Δp_{max} must be reduced by 'a'

iii) k must be increased by 'a'

iv) t will be reduced by a^2

Approach 2: Same fluids, same porous medium, same pressured geometric similarity.

This approach scales the capillary forces properly but at the expense of not properly scaling the gravitational forces. While this approach assures proper scaling of the irreducible saturations and the relative permeabilities it is not applicable in the process dominated by gravitational effects.

The implication of these scaling criteria for a model reduced in length by a scaling factor of 'a' are

i) Δp_{max}, T_b/T_i, k, ϕ, S_{oi} must be the same

ii) t will be reduced by 'a^2'

Approach 3: Same fluids, same porous medium, same pres geometric scaling relaxed.

To combine the advantages of using the same fluids, the same porous medium and similar pressure and temperature conditions with proper scaling of the gravitational effects, the requirement of the geometric similarity must be relaxed, i.e., the group l/h cannot be satisfied. The implication of these scaling criteria for a model reduced in length by a scaling factor of 'a' are

i) Δp_{max}, T_b/T_i, k, ϕ, S_{oi} must be the same

ii) reservoir must be horizontal

iii) t will be reduced by 'a^2'

Steam Injection

Steamflooding is a well-known method for recovering oil fromheavy oil reservoirs and emphasis has been placed on improving steamflood performance, such as oil-steam ratio, oil recovery, thermal efficiency, etc. Many laboratory studies have been conducted in an effort to improving steamflood performance. Some of the experiments were designed to study the various mechanisms involved and to extend the results to make field predictions by using numerical simulators. Other experiments, referred to as scaled experiments, were designed to allow the relative influence of the various mechanisms observed in an experiment to be similar to those expected in the field and to predict field performance. In this context, the effects of various parameters, such as, injection rate, production pressure, slug size, completion intervals, well pattern geometry, steam additives, bottom water, reservoir heterogeneities, and steam quality, have been studied. Also, scaled models have been used to calibrate numerical models and provide insight into the effects of mechanisms which may not be properly incorporated into numerical simulators.

Different approaches have been used in scaling steamflood processes. These may be divided into two broad categories; high pressure models (operating at field pressures) or low pressure (or vacuum) models (operating at pressures below atmospheric pressure). The critria used most widely for low pressure models are those presented by Stegemeier. They demonstrated that a vacuum model containing different porous media from that of the prototype may be used to predict field performance accurately. The scaling groups derived by these authors are listed in Table 2. A set of scaling groups was derived by inspectional analysis and then engineering judgementwas used to reduce the set of scaling groups into a set of scaling groups which could generally be matched between the scaled model and the field prototype. In their derivation, they allowed the existence of oleic, aqueous and steam vapour phase. However, capillary pressure effects were negelcted alongwith the mass transfer between oleic and vapour phases. Also, since different porous media for the model and the prototype was used, the scaling of relative permeabilities and irreducible saturations is questionable. Besides, a practical limitation results from the possible problems associated with finding model materials and fluids with the properties necessary to satisfy the scaling groups. The failure to scale the capillary pressure is acceptable only when the viscosity of the prototype oil is very high. In this case, a large mobility ratio leads to a weak dependence on the capillary number. Also, the inability to scale relative permeability does not pose serious problem as most of the field displacements are dominated by mobility ratio rather than relative permeabilities. The criteriaused most widely for high pressure models are those presented by Pujol and Boberg. The scaling groups are listed in Table 3. In their derivation of the scaling groups they have neglected oil-gas mass transfer. These models typically employ the same fluids in the model as occuring in the prototype. These criteria may approximately scale rock-fluid interactions, fluidproperties, emulsification, steam distillation, gas solubility, and compressibility more closely than low pressure models.

However, low pressure models are easier to build and operate and may better scale temperature and velocity distributions due to better scaling of the steam saturation pressure vs. saturation temperature relationship.

To study steam processes in which additives might be used to improve the process, high pressure models, where the same fluids under field conditions of pressure and temperature, are required. Some phenomena, such as the irreducible saturations or the relative permeabilities, may be better scaled if the same porous medium could be used in the model as in the prototype. In order to allow similar similar conditions of pressure or the same porous medium to be used in the model, Kimber developed a new set of scaling criteria by inspectional and dimensional analyses for the steam additive processes. Table 4 lists the general set of these scaling groups.

They presented methods which, by relaxing the requirements of geometric similarity, allow the same fluids and the same porous media to be used to scale steam or steam additive processes for horizontal reservoirs. ttarting from this general set they determined relaxed sets of scaling criteria, particular to the major mechanisms of a process. In their derivation they allowed three phase flow (oleic, gaseous, and aqueous) with mass transfer of the additives within the oleic and gaseous phase due to concentration diffusion, advection, and dispersion. However, kinetic, potential and viscous dissipation energies were assumed negligible compared to the conductive heat flux. They reported five different subsets of sacling groups depending on which scaling criteria are relaxed. Due to the novelty of this approach, all of these approaches will be discussed.

Approach 1: Same fluids, different porous media, different pressure drop, geometric similarity

For this approach x_{1R} , x_{2R}, andx_{3R} are set equal to L (See Table 4). In order to satisfy the groups scaling geometry, viscous forces and gravitational forces, the pressure drop in the model has to be different. This criterion requires the need of a different porous medium for the model than that of the prototype. Consequently, this method cannot scale the saturation pressure vs. saturation temperature relationship for steam, leading to an improper match for boundary conditions fortemperature and poor scaling of heat losses from the steam zone. Steam density and other properties which depend on pressure are not scaled properly either. The effects of dispersion andcapillary pressure are not scaled and the scaling of the irreducible saturations and relative permeabilities is questionable due to the use of different porous media. As a whole, this approach satisfies all the scaling groups except Nos. 25 to 28. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing thesame fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, ΔT_{max} must be the same

ii) H, W, Δp_{max}, $(p_i - p_{prOd})$, W_{aw}, W_{gs}, W_{ls} must be reduced by 'a'

iii) k must be increased by 'a'

iv) t will be reduced by 'a^2'

Approach 2: Same fluids, same porous medium, same pressure drop, geometric similarity

For this approach reference dimensions are assigned the same values as in Approach 1. However, same porous medium is used for the model and the prototype. This allows pressure dependent properties to be more accurately scaled. Also, irreducible saturations, relative permeabilities, diffusions, viscous forces and heat transfer are properly scaled. However, gravitational forces are not scaled properly. Consequently, this approach may not be used in process dominated by gravitational effects. Also, dispersion at high flow rates is not scaled. With these limitations this approach satisfies all but No. 29 of the scaling groups mentioned in Table 4. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, p_i, k, ΔT_{max}, p_{prOd}, Δp_{max} must be the same

ii) H, W, W_{aw}, W_{gs}, W_{ls} must be reduced by 'a'

iii) t will be reduced by 'a^2'

Approach 3: Same fluids, same porous medium, same pressure drop, geometric scaling relaxed

In order to scale gravitational forces by using the same porous medium for the model and the prototype, the geometric similarity must be relaxed. If the vertical pressure gradient due to viscous and capillary forces is small, this approach scales viscous forces in the case of horizontal reservoirs. The conduction of heat in the vertical direction, the capillary forces and the effects of dispersion may not be scaled properly. For this approach x_{2R} is chosen to equal to $\rho_{lR} g_R L^2 / p_{IR}$. Consequently scaling groups 2, 4-5, and 25-28 are not satisfied. Also groups Nos 29 and 31 become $H p_{IR} / \rho_{lR} g_R L^2$ and $A_{injR} p_p p_{IR} / L^3 \rho_{lR} g_R$ respectively. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, p_i, T_i, ΔT_{max}, k, p_{prOd}, Δp_{max} must be the same

ii) W must be reduced by 'a'

iii) H, W_{aw}, W_{gs}, W_{ls} must be reduced by 'a^2'

iv) the reservoir must be horizontal

v) t will be reduced by 'a^2'

Approach 4: Same fluids, same porous medium, samre pre geometric scaling relaxed

This approach is capable of scaling dispersion at high flow rates. This approach attempts to scale processes dominatedby transverse dispersion. While viscous and dispersive effects are balanced, gravitational and capillary effects are not scaled properly. For this approach x_{2R} is chosen to be equal to $(\phi_R S_{lR} \chi_R d_{pR} L)^{1/2}$ Consequently, similarity groups Nos. 2, 4-5, 25-28 are not satisfied and group Nos. 29 and 31 become $H/(\phi_R S_{lR} \chi_R d_{pR} L)_{1/2}$ and $A_{inj}/(\phi_R S_{lR} \chi_R d_{pR} L)^{1/2}$ respectively. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, p_i, T_i, ΔT_{max}, k, p_{prOd}, Δp_{max} must be the same

ii) W must be reduced by 'a'

iii) H, W_{aw}, W_{ls}, W_{gw}, W_{ls} must be reduced by '$a^{1/2}$'

iv) t will be reduced by 'a^2

Approach 5: Same fluids, different porous medium, different pressure drop, geometric scaling relaxed

In order to scale the gravitational effects alongwith dispersions at high flow rates, Approach 5 uses different pressure change and porous media. Consequently, this approach suffers from similar drawbacks as in Approach 1. Besides, time is scaled down to a factor of 4/5 rather than 2 for other cases. Also, this approach does not scale the effects of capillary forces nor heat conduction in the vertical direction within the reservoir. The saturation pressure vs. temperature relationship for steam and the boundary conditions for temperature may be poorly scaled as well. In this approach, x_{2R} is assigned to be equal to . $\rho_{lR} g_R L_2 / \rho_{lR}$ Consequently, scaling groups Nos. 2, 4-5, 25-28 are not satisfied. Also, group Nos. 29 and 31 become $H p_{lR} / \rho_{lR} g_R L^2$ and $A_{injR} p_{lR} / L_3 \rho_{lR} g_R$), respectively. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, $F_{,}$,T_{i}, ΔT_{max}, must be the same

ii) L, W must be reduced by 'a'

iii) k must be increased by '$a^{2/5}$,

iv) Δp_{max}, W_{aw}, W_{gs}, W_{ls} must be reduced by '$a^{8/5}$

v) t will be reduced by '$a^{4/5}$,

v) H must be reduced by 'a

Niko and Troost[13] derived scaling criteria for cyclic steam stumulation in a radial, two-phase (oil-steam) system, which is given in Table 5. In order to simulate radial, compressible flow, the scaling criteria require the use of an oil in the model, the compressibility of which must be scaled up by the factor a, but is otherwise identical to the field oil. The authors resolved this difficulty through the use of a hydraulic analog connected in series with the porous medium model. This procedure was apparently successful in simulating the field results. There does not appear to be other successful laboratory models for scaled experiments of cyclic steam stimulation.

■ In Situ Combustion

To date, a complete analysis of combustion scaling has not been carried out. The first attempt in this direction was made by Binder . Their scaling criteria are listed in Table 6. These criteria are based upon a simplified version of combustion, considering single phase gas flow (allowing the presence of a second phase) and conductive heat transport. Nevertheless, the authors obtained good agreement between the results for a large and a small model, showing that for the type of experiments conducted (dry combustion), the scaling criteria derived were adequate. Unscaled wet combustion experiments were also carried out. The authors also showed that their model results were in fair agreeement with the results of three major field tests conducted at that time (1962).

It should be recognized that a properly scaled model of combustion must include all features of steam injection, because a steam drive is in effect ahead of the combustion zone. Furthermore, other effects such as cracking, vaporization-condensation phenomena, miscible, carbon dioxide, and emul drives should be included. This is also true for the simpler, unscaled fire tube tests. Such tests give quite reliable results for dry combustion so far as the stoichiometric parameters are involved. However, they can be quite erroneous where wet combustion studies are concerned.

SCALING CRITERIA FOR POLYMER, EMULSION AND FOAM FLOODIN EXPERIMENTS

The use of polymer, emulsion and foam has been a subject of many investigations in petroleum industry for many years. These materials have been used as mobility control or diverting agents in different enhanced oil recovery techniques, such as gas drive, steam injection, waterflood or micellar flood. Many studies have shown that these materials may improve oil recovery by a substantial amount. HHowever, laboratory studies performed to-date have used unscaled or only partially scaled models. Therefore, the quantitative results obtained from polymer, emulsion and foam flooding experiments are not applicable to the field. In order to scale up laboratory experiment results for field application, the model has to be properly scaled. This requires detailed knowledge of polymer, emulsion and foam flow through porous media. Only recently Islam and Farouq Ali reported a new set of scaling groups for polymer, emulsion and foam flooding experiments. They discussed the mechanisms of improved oil recovery with these materials and used various possibilities in order to describe these mechanisms mathematically. Then they used inspectional analysis to derive the scaling criteria for these processes. Due to the complexity and uncertainity of the flow mechanism involved, many of the cases studied are hypothetical and have to be further studied to devise a scaled model. These scaling groups will be discussed in the following sections.

■ Polymer Flood and Waterflood

It was assumed that the process consists of two-phase flow: the oleic phase and the aqueous phase. The oleic phase contains only oil and the aqueous phase contains water and polymer; the mass transfer between water and oil or polymer and oil was neglected. It was also assumed that the polymer resides in the aqueous phase due to its hydrophilic nature that makes it dissolve and hydrolyze in water. They used Fick's equation for dispersion in the aqueous phase. Table 7 lists the complete set of scaling groups for polymer and waterflood process. Five different approaches depending on the scaling groups relaxed were attempted for this process. These approaches are similar to the five already described in the steam injection section.

Emulsion Flood and Waterflood

Three different sets of assumptions are used for this process. The governing equations have been set up according to the assumptions made.

Emulsion and water flood - two-phase flow

This process was considered to be two-phase flow. These phases are the aqueous phase and the oleic phase. The components present in the oleic phase are oil and emulsion and the the components present in the aqueous phase are water and emulsion. The complete set of scaling groups are listed in Table 8. To be noted that these criteria are also applicable to micellar flood experiments for which it is more likely to have a two-phase flow. Five different approaches were suggested for this set of scaling group as well. They are similar to the previous ones. Table 8 lists the general scaling criteria for this proccess

Emulsion and waterflood - Emulsion soluble in aqueous phase only

In this process the water-rich emulsion solution was assumed to mix with the aqueous phase only. The scaling groups are listed in Table 9. The same five approaches were suggested for this process as well.

Emulsion and water flood - Three-phase flow

In this process a three-phase flow was considered. These phases are aqueous phase, oleic phase and emulsion phase. All these phases flow simultaneously under equilibrium conditions in a porous medium. This treatment of the process requires three-phase relative permeability data for water, oil and emulsion system. The idea of three-phase flow was earlier suggested by Islam and Farouq Ali who conducted experimental studies on emulsion flow in porous media. Table 10 lists the complete set of scaling groups for this process. Once again, five different approaches were proposed for this case.

Foam Injection

The foam flooding process mechanism is debatable as the exact nature of flow is not clearly understood. Two different scenarios were considered. Both of these have some experimental evidence. These are discussed below.

Foam Flood - Four-phase flow

In this representation, the foam flooding process is considered to be four-phase flow. The phases are: aqueous phase, foam phase, oleic phase and gaseous phase. Such a depiction of the process is drawn from the observation that whenever a gas (nitrogen) is injected, only a fraction of the injected gas takes part in producing foam while the rest of it flows as an independent phase. Even though there is some controversy concerning the extent to which foam flows as a body, it was assumed that foam and all other phases flow simultaneously. For this process four-phase relative permeability data are required. Among other assumptions, it was assumed that nitrogen is the gas that is being injected and it does not have any miscibility with the oleic or aqueous phase. The components present in foam phase are water, nitrogen and surfactant, components present in gaseous phase are nitrogen and surfactant, components present in the aqueous phase are surfactant and water. The scaling groups for this process are listed in Table 11.

Foam Flood - Three phase flow

This representation of the process is considered to be three-phase flow. The phases are: aqueous phase, foam phase and oleic phase. Therefore, the amount of gas (nitrogen) injected is considered to be just enough to create foam that leaves no free gaseous phase in the system. For this process three-phase relative permeabilities are required. Similarly to the previous case, it is assumed that nitrogen is the gas that is being injected and it does not have any miscibility with the oleic or aqueous phase. The components present in the foam phase are water, nitrogen and surfactant; components present in oleic phase are oil and surfactant; and the components present in the aqueous phase are surfactant and water. The scaling groups are listed in Table 12.

Comparison of Different Scaling Approaches

Polymer and Water Flood

Since gravitational effect is not important in this system, Approach 2 is the most suitable set. As this approach uses the same porous medium for the model and the prototype, the effect of adsorption and retention (the most important phenomena in polymer flooding) may be properly scaled. Besides, this approach does not have any risk of altering irreducible saturation or relative permeabilities as experienced by the Approach 1. Approach 3, which uses the same fluids and porous medium, scales gravitational effects properly at the expense of relaxing geometric similarity. However, the effect of dispersion is magnified in this model. This might be a point of concern as dispersion is not negligible in a waterflood following polymer injection. Approaches 1 and 2 scale the effect of diffusion properly. However, for the case of polymer injection dispersion is a more important phenomenon. Pozzi and Blackwell showed conditions for miscible processes where scaling viscous and dispersive forces can be achieved by relaxing geometric and gravitational scaling requirements. Approach 4 properly scales dispersion at the expense of gravitational and capillary forces. However, as it uses the same porous medium it scales relative permeability and irreducible saturations properly. Approach 5 properly scales gravitational forces and dispersion but suffers from similar shortcomings as Approach 1.

If polymer is considered as a mobility control agent for a heterogeneous reservoir (such as a reservoir containing a bottom-water zone) the resistance factor plays an important role. In order to obtain a proper resistance factor, adsorption and mechanical entrapment should be similar in the model and the prototype. This shows the need of using the same porous media for the model and the prototype. Dispersion plays an important role in polymer flooding but a more dominant mechanism is the viscous instability, which arise when waterflooding following a polymer flood. The contribution of the dispersion factor may be seen by comparing the results with Approaches 2 and 4.

As has been mentioned, in order to have the same reference concentration in the model and the prototype a similar polymer concentration and type should be used. This would ensure the scaling of the pressure-dependent properties, adsorption, and the blocking action with polymer.

Emulsion and Water flood

There have been three different cases studied. However, each of these cases is applicable depending on the quality of emulsions used. It is possible to obtain an emulsion that is miscible in both aqueous and oleic phases. On the other hand, a low-quality emulsion would be practically immiscible in the oleic phase. In either case, however, the effect of dispersion is important in the aqueous phase. Unlike polymer flood, there is no resistance factor involved in the governing equations for emulsions. However, the blocking action may be incorporated in terms of relative permeabilities of the phases considered. The fact that emulsion does improve the oil recovery more than what it would by just improving the mobility ratio, makes the scaling more complicated. When, emulsion is being considered as a blocking agent, matching the relative permeability curves is more important. This warrants the need of having the same porous media for the model and the prototype. Approach 4 scales the dispersion term using the same porous media, and therefore, needs to be considered for best scaling results.

One is limited to using the same type and quality of emulsion in order to have the same refernce concentration in the model and the prototype. It will also dictate similar dispersion and diffusion. Viscous instability is not a major factor to be considered in an emulsion flood and therefore scaling dispersion and diffusion would lead to adequate results.

Foam Injection

This is the only system in which gravity plays an important role. This leads to the choice of Approach 3 that scales the gravity effects properly. However, scaling foam injection would need most careful treatment as the recovery depends largely on factors, such as type and concentration of surfactant, absolute permeability, and even injection pressure. One has to have the same concentration and quality of foam in order to ensure similar blocking action on nitrogen. This will also ensure similar foam stability, and bubble size that play an important role in blocking action with foam. Also, the type of porous medium plays an important role unless flow region for which foam flood performance is sensitive to the permeability is avoided.

As has been pointed out, if four different phases are flowing simultaneously, one has to have a more detailed study in order to match the relative permeability data. This can be avoided only when the amount of surfactant is such that only three-phase flow in the system. In this situation, foam flood may be treated as a three-phase problem if a single set of relative permeability data is capable of representing the process adequately.

One of the puzzling factor is the fact that the behaviour of all three mobility control agents is different in homogeneous and heterogeneous porous media. It has been shown recently that the improvement of emulsion and foam is better in the presence of a bottom water zone. For polymer, this has been a well-known fact. These observations lead to believe that the existence of a bottom-water zone should be considered in deriving the scaling groups. Our contention is when a bottom-water zone is present it's existence does not show only in terms of the oil-to-water zone thickness ratio and that the resistance factor or blocking mechanism have to be considered.

IMMISCIBLE CARBON DIOXIDE INJECTION

Immiscible carbon dioxide flooding for a moderately heavy oil is a well known recovery method for thin, marginal or otherwise poor heavy oil reservoirs that are unsuitable for thermal recovery processes. Basically four different immiscible carbon dioxide/water displacement processes can be used for recovering heavy oil: straight or continuous carbon dioxide injection, carbon dioxide slug process, injection of alternate slugs of carbon dioxide and water, and simultaneous injection of carbon dioxide and water. A set of scaling groups was developed by Rojas who derived these groups from inspectional and dimensional analyses. In his derivation, he assumed instantaneous equilibrium in the reservoir. These scaling groups are listed in Table 13.These scaling groups scale gravitational and viscous forces, water-gas ratio of slug volumes properly. However, the capillary and diffusive forces are neglected in these scaling groups.

Recently Lozada and Farouq Ali developed partial differential equations governing immiscible carbon dioxide drive for moderately heavy oil with partial equilibrium among the gas, oil and water phases. They also reported a set of scaling groups derived both from inspectional and dimensional analyses. Since initially carbon dioxide is not in equilibrium with the heavy oil, this study using partial equilibrium, that allowed interfacial mass transfer, was justified. Also, recovery efficiency of the displacement of moderately heavy oil by carbon dioxide is dependent on the development of favourable phase behaviour effects, resulting from mixing between the fluids. This study, therefore, revealed under what conditions thermodynamic equilibrium is reached in the porous medium, and the effects of partial equilibrium in the recovery of heavy oil by carbon dioxide. The scaling groups are listed in Table 14. Six different approaches depending on the scaling groups relaxed were reported. These approaches are discussed below:

Approach 1: Same porous medium, same fluids, same press drop, geometric similarity and same temperature

x_{1R},x_{2R}, and x_{3R} are set to L for this approach. This approach enabled proper scaling of all the pressure, temperature a properties, such as, viscosity, density, solubility, and equilibrium constants to be scaled properly. This approach has the advantages of using the same porous media for the model and the prototype and scales the capillary and viscous forces properly. However, gravitational forces or dispersion at high flow rates are not scaled. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, ΔT_{max}, k, $(p_i - p_{prOd})$ must be the same

ii) H, W, W_a and W_{CO2} must be reduced by 'a'

iii) t will be reduced by 'a^2'

Approach 2: Same fluids, same porous medium, same temperature, same pressure drop and geometric similarity relaxed

In order to satisfy the gravitational forces, this approach relaxes the geometric scaling. For this approach reference vertical coordinate is chosen to be $\rho_{IR} g_R L^2 / p_{IR}$. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, ΔT_{max},, Δp_{max} k, $(p_i - p_{prOd})$ must be the same

ii) W must be reduced by 'a'

iii) H, W_a and W_{CO2} must be reduced by 'a^2'

iv) t will be reduced by 'a^2'

Approach 3: Same fluids, same porous medium, same pressure drop, same temperature, geometric similarity relaxed to satisfy the dispersion group

In this approach, the viscous force ratio, viscous over gravity force ratio, mass transfer over any other forces are not satisfied. However, dispersive forces and dispersive over viscous forces at high flow rates are satisfied. The reference vertical coordinate is chosen to be $X_{2r}=(\phi_R S_{lR} \chi_R d_{pR} L)^{1/2}$. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, DT_{max}, k, Δp_{max}, $(p_i - p_{prOd})$ must be the same

ii) W must be reduced by 'a'

iii) H, WCO_2 and W_a must be reduced by 'a$\underline{1/2}$

iv) t will be reduced by 'a^2'

Approach 4: Same fluids, same porous medium, different pressure drop, and geometric similarity

In this approach, the pressure drop is relaxed to in order to balance viscous forces and the ratio of viscous and gravitational forces. However, capillary forces are not properly scaled. This approach has the disadvantage of using a very long time. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, DT_{max}, k, must be the same

ii) W, H, Δp_{max}, $(p_i-p_{pr}O_d)$ must be reduced by 'a'

iii) W_{CO_2} and W_a must be reduced by 'a^2'

iv) t will be reduced by 'a'

Approach 5: Same fluids, different porous media, different pressure drop, and geometric similarity

In this approach, geometric similarity, viscous forces and gravitational forces are scaled properly. However, capillary forces are not scaled properly and the scaling of the irreducible saturations and relative permeabilities is questionable. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, , must be the same

ii) W, H, Δp_{max}, $(p_i-p_{pr}O_d)$, ΔT_{max}, k, W_{CO_2} and W_a must be reduced by 'a'

iii) t must be reduced by 'a^2'

Approach 6: Same fluids, different porous media, different pressure drop and geometric similarity relaxed

In this approach, the viscous and gravitational forces are balanced in addition to the dispersive forces in the transverse direction. This is done by relaxing the requirement for geometric similarity. The vertical reference coordinate is chosen to be equal to $p_{IR}g_R L^2/p_{IR}$. The implications of these scaling criteria for a model reduced in length by a scaling factor of 'a' and employing the same fluids as that of the prototype are:

i) ϕ, S_{ai}, S_{gi}, F, T_i, , must be the same

ii) W, L must be reduced by 'a'

iii) H must be reduced by '$a^{2/5}$'

iv) Δp_{max}, $(p_i-p_{pr}O_d)$, W_{CO_2} and W_a must be reduced by '$a^{8/5}$'

v) k must be increased by '$a^{2/5}$'

vi) t will be reduced by '$a^{4/5}$'

OTHER PROCESSES

Scaling for various combination type processes are largely unavailable. In some cases, it is clear that such criteria would be difficult to satisfy even if derived. In this context, combinations of foam or emulsion with steam injection may be mentioned. Miscible-thermal displacement falls under this category too. Greenkorn reported scaling criteria for single phase miscible displacement under nonisothermal conditions. The groups derived by him are listed in Table 15.

Kabir et al.[31] presented a new scaling method for modeling leaching of uranium. Their method may be applied in solvent leaching of bitumen. They simplified a 2-D problem to a assemblage of 1-D problems. When dispersion is neglected, the set of 1-D problems is further reduced to a single 1-D problem. The 1-D calculation accomodates chemical-rock interaction and the streamline model accounts for areal sweep. The agreement between results of the scaled model and the numerical model was excellent. This scaling was tested also by Kaleli who compared scaling results with numerical and experimental results[33] and showed the validity of the model until the dissolution was largely complete. The model was inadequate only when dispersion started to dominates, following solvent leaching.

■ PROBLEMS IN MODELING

Apart from the difficulties in properly scaling different mechanisms involved, modeling of EOR processes has still other complicating features. None of the scaling groups for thermal methods has attempted scaling distillation, emulsification, gas solubility or rock-fluid interaction. Besides, the temperature dependence of rock properties and compressibilities has not been dealt Even though using some of the approaches this problem may be minimized (e.g., Approaches 2, 3, and of Kimber , proper scaling of these phenomena needs more rigorous derivation of the scaling groups.

Some of the recent studies have suggested that relative permeabilities in a multiphase system are functions of other parameters in addition to being functions of fluid saturations. This poses a very difficult modeling problem for all the EOR processes. This observation is especially true for the foam flooding processes for which relative permeabilities have been reported to be a function of flow rates, foam quality, fractional flow, and fluid saturations.[19,25,36]

Another problem particular to EOR modeling is viscous fingering. Even though viscous fingering has been extensively studied in single phase miscible or two-phase immiscible displacements, little information is available in quantifying this problem in an EOR process involving miscible and immiscible displacements at the same time. Bentsen argued that unstable displacement (involving viscous fingering) may be properly scaled by using the same instability number in the model as in the prototype. Coskuner and Bentsen derived a universal dimensionless scaling group and its critical value at the onset of instability for miscible displacement in a Hele-Shaw cell. This derivation was based on the variational technique and is capable of considering the effect of length of a Hele-Shaw cell on the criterion of the onset of instability. Lenormand used percolation theory to develop scaling laws for immiscible displacements with capillary and viscous fingering. While these works give some insight into how to treat viscous fingering problem, a universal scaling criterion for a complex EOR problem involving miscible, immiscible and thermal problems is far from developed. Moreover, very little experimental evidence in porous media is available to support any of these approaches.

APPLICATIONS AND COMPARISON WITH FIELD RESULTS

Many experiments have been conducted with both semi scaled and scaled physical models to examine thermal recovery processes. However, few experimental works have been reported in areas of immiscible carbon dioxide displacements. On the other hand, no scaled model results has been reported for emulsion, foam or polymer flood experiments due to the lack of proper scaling criteria. However, many experiments have been conducted in unscaled models in order to identify the major mechanisms involved in the process. Some of the experiments will be discussed in the following section.

Steam Injection

The scaling criteria developed by Pujol and Boberg are often used in high pressure-model studies of steam injection. Pursley applied the Pujol-Boberg scaling criteria to simulate reservoir conditions existing at Cold lake, Alberta using several three-dimensional models. The prototype oil viscosity was approximately 100,000 mPa.s and in some experiments the reservoir contained a bottom-water zone and/or a gas cap. With bottom water present, he found that recovery was significantly higher because the steam tended to override and contact a greater portion of the oil sand. Huygen used three-dimensional, high pressure (7 MPa) model packed with Berea sand to examine the steamflood recovery of eight different crudes. In a later study, Huygen and Lowry performed experiments to study steamflooding in the presence of a bottom-water zone. Ehrlich conducted experiments in a three-dimensional model, scaled following the Pujol-Boberg criteria, to study steam displacement in the Wabasca Grand Rapids 'A' sand. Singhal and Lo employed Pujol-Boberg scaling criteria in their scaled model studies. Their experiments were carried out in a scaled model with intermediate range of pressure (100-117 kPa). They observed that the hot condensate zone ahead of the steam zone exhibited severe viscous fingering resulting in early breakthrough but that the steam zone did not exhibit fingering.

Low pressure-models (in vacuum) employing Stegemeier et al. criteria have been used in several studies. Stegemeier performed scaled experiments to design or to provide operational assistance for several of Shell's steam drive projects. They provided results from two of their large model studies for the Mt. Poso and Midway Sunset fields, as examples of the type of information which may be derived from vacuum model studies. Prats conducted numerous experiments using vacuum models employing Stegemeier scaling criteria. His study was focused on the Peace River, Alberta oil sand deposit where a bottom-water layer exists. Five prototypes were examined. It was concluded that each prototype required a unique operating strategy in order to obtain optimal recovery. Doscher used a vacuum model based on the scaling criteria of Stegemeier with modifications. He developed scaling parameters from similarities in an integral form, based on a study of Yortsos, rather than a differential form as used by Stegemeier This model was used by Doscher and Huang to investigate the steam drive performance in a Kern River type heavy oil field. The same model was also used by Doscher and Ghassemi who reported that the viscosity of the crude oil is a very important parameter that affects the efficiency of the steam drive process. More recently, Proctor and Farouq Ali conducted some scaled model studies based on Stegemeier criteria. Their work addressed

Lloydminster, Saskatchewan, type reservoirs characterized by a viscous oil (1275 mPa.s at reservoir temperature) and a thin pay (6-13 metres). Some of these experiments employed a bottom-water layer as well.

■ Immiscible Carbon Dioxide Injection

Even though the idea of using carbon dioxide to improve oil recovery has a long history, only recently scaled model studies have been reported. Rojas and Farouq Ali used the scaling criteria developed by Rojas to obtain carbon dioxide/brine injection strategies for heavy oil recovery from thin formations. Experiments were conducted in a scaled model, with Alberfeldy-Lloydminster heavy oils (1000-5000 mPa.s), using a small slug (20% hydrocarbon pore volume) of subcritical carbon dioxide in a rectangular model, designed to simulate a thin formation. They reported that the injection of alternate slugs of carbon dioxide (at 5.5 MPa, 21-23^{o} C) and brine yielded the best results: highest incremental recovery and lowest CO_2 requirement.

Several field pilot results using immiscible carbon dioxide injecti have been reported in recent years. Some of the encouraging results have been reported in the U.S.. In Canada, many fields have been reported as potential candidates for carbon dioxide immiscible flooding.

■ Polymer, Emulsion and Foam Flooding

No scaled model study has been performed in any of these EOR techniques. However, numerous experiments have been conducted in unscaled models. The model studies for these techniques have been summarized in recent study by Islam and Farouq Ali, They also conducted unscaled model studies to investigate the roles of major mechanisms involved. This information was used in deriving scaling criteria. However, no work has been reported on scaled model studies using these scaling criteria.

PHYSICAL MODELS VS. NUMERICAL MODELS

The development of mathematical models of thermal and several chemical recovery processes has progressed to a point where one may wonder if physical models are at all necessary. As a matter of fact, they are, because the mathematical models still lack the microscopic simulation of the recovery processes, and may be very time consuming and expensive if relatively fine grids are employed, not to mention the problem of stability and numerical dispersion. Also, mathematical models for combination processes, such as, steam-emulsion flow, miscible-thermal methods, foam flow are yet to be developed. On the other hand, physical models too have limitations imposed by inadequate scaling. It follows, therefore, that both physical and mathematical models should be used together for studying EOR techniques.

A mathematical model can be used to obtain information on the error incurred due to improper scaling, and in any case, it can be used to simulate laboratory experiments, whether it is scaled or not. Recently Islam and Farouq Ali used laboratory experiment results to define the flow mechansm in emulsion flooding and developed a simulator for simulating emulsion flood results. Similar approach was also reported in the case of polymer flood. Aziz and Mugan, on the other hand, have reported an instance where the results of a numerical model were used to adjust a physical model of the water coning phenomenon. A mathematical model is capable of simulating no more than the physical processes built into it. A physical model, even though unscaled, can provide valuable insight into the formulation of the mathematical model. Once the most important phenomena to be modeled are identified, the mathematical model can be used to assess their relative magnitudes in the framework of field conditions.

CONCLUSIONS

- ☐ *The following conclusions are drawn on the basis of the above discussion:*
- ☐ *(1) "Scaled" models can be designed for any EOR process provided only the salient features of these processes are modeled.*
- ☐ *(2) Scaling criteria for most of the combination EOR processes, such as emulsion-steam, foam-steam flow, etc. are still unavailable. Nor can the numerical models can fill this gap.*
- ☐ *(3) Very little work has been done in deriving more rigorous scaling criteria for combustion process.*
- ☐ *(4) A new approach shows that it is possible to relax some of the scaling requirements (including geometric similarity) in order to construct semi-scaled models for complex EOR methods. This ap-*

proach has been applied for miscible-thermal techniques, partial equilibrium carbon dioxide drive, foam injection, and emulsion and polymer floods.

- *(5) Unscaled or semi-scaled models can be of value in the formulation of numerical models (e.g. in the identification of the processes to be modeled). The latter can be used to analyze the error incurred as a result of inadequate scaling. The two type of models thus complement each other.*

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NOMENCLATURE

a	geometrical scale-down ratio, model length/prototype length
A_{inj}	area open for flow in an injection or producer well
A_p	$B.C_{rp}^*$
b	distribution factor of the interfacial force (see Eqns. 25 and 26 in Ref. 6)
B	K_1/K_2
B_i	volumetric factor of carbon dioxide
c,C	specific heat
C_{ij}	concentration of component j in phase i
C_{ij}	concentration of component j in phase i
C_{rp}	amount of polymer adsorbed per unit mass of rock
C_{rp}^*	maximum adsorptive capacity of rock
D	diffusion, dispersion coefficient
D^*	molecular diffusion coefficient
D_T	transverse hydrodynamic dispersion coefficient
D_L	longitudinal hydrodynamic dispersion coefficient
D_i	convective dispersion tensor for i phase
D_{ij}^*	molecular diffusion tensor for component j in phase i
D_{ij}	hydrodynamic dispersion tensor for component j in phase i
d_p	mean particle diameter in the porous medium
F	formation electric resistivity factor
f_s	steam quality
g	acceleration due to gravity
g_c	conversion factor, dimensionless
h_i	enthalpy of the i phase
H	height or thickness of the reservoir or model
H_s	enthalpy of injected steam above reference temperature

i_s	mass steam injection rate
J	Leverett function = $p_c\sqrt{k}/\sigma\sqrt{\phi}\cos\theta$
k,K	absolute permeability
k_{hj}	thermal conductivity of j
K_i	effective permeability to phase i
K_{ijk}	equilibrium K-values for component i partitioning between phases j and k.
K_1	kinetic rate constant for adsorption m^3/kg-day
K_2	kinetic rate constant for adsorption kg/kg-day
L,l	length of the reservoir of model
L_v	latent heat of vaporization
N_{ijl}	mass transfer rate of the component i in or out of j phase through the jl interface
p	pressure
p_{cij}	capillary pressure for phases i and j
q_o	volumetric oil production rate
Q	injection flow rate
r_e	external radius
R_{si}	solution gas in i phase
S_i	saturation of i phase
t	time
T	Temperature
v	superficial velocity
v^*	slug volume (in fraction of the pore volume of the system)
W	width of the reservoir or model
W_{ij}	injection rate of component j in i phase
x_i	cartesian coodinates
z	elevation of reservoir above a datum

α	thermal diffusivity
β	coefficient of cubic expansion
μ_i	viscosity of i phase
M	morphology factor
θ	wetting angle of fluid interface
σ_{ij}	interfacial tension between phases i and j
ρ_i	density of i phase
ϕ	porosity of reservoir
ψ	angle of inclination of sand with the horizontal
χ	inhomogeneity factor

Subscripts

a	aqueous phase
b	injected water
c	cap of base rock
co_2,g	CO_2 of the gas phase
co_2,l	CO_2 of the oleic phase
co_2,a	CO_2 of the aquesous phase
D	dimensionless quantity
f	foam phase
g	gas phase
H	horizontal
inj	located at the injection well
i	initial
l	oleic phase
m	emulsion phase or component
N	nitrogen component

Table 1: Scaling Groups for Hot Water Injection into an Oil-Bearing Sand
(After Geertsma *et al.*[6])

$$\frac{l}{h}\ ,\ \psi\ ,\ \phi,\ \mu_{oi}/\mu_{wi}\ ,\ \rho_{oi}/\rho_{wi}\ ,\ kt\rho_{wi}g/\mu_{wi}l\ ,$$

$$t(\sigma\cos\theta)_i\ \sqrt{k}/\mu_{wi}l\ ,\ J\ ,\ b\ ,\ k_{ro}\ ,\ k_{rw}\ ,\ S_{oi}\ ,$$

$$\beta_o T_i\ ,\ \beta_o/\beta_w\ ,\ \rho_{wi}C_w/\rho_{oi}C_o\ ,\ \rho_r C_r/\rho_{oi}C_o\ ,$$

$$k_{hw}/k_{ho}\ ,\ k_{hr}/k_{ho}\ ,\ k_{hc}/k_{ho}\ ,\ \frac{k_{ho}\,t}{\rho_{oi}C_o l^2}\ ,$$

$$\rho_c C_c/\rho_{oi}C_o\ ,\ T_b/T_i\ ,\ \mu_o(T)\ ,\ \mu_w(T)\ ,\ \frac{vt}{l}\ \text{or}\ \frac{k\Delta pt}{\mu_{wi}l^2}$$

$$\sigma(T)\ ,\ l/\sqrt{k}\ ,\ \rho_{wi}l\sqrt{k}/t\mu_{wi}\ ,\ \rho_{wi}C_w T_i t/\mu_{wi}$$

Table 2: Scaling Groups for Steam Injection
(After Stegemeier *et al.*[8])

$$\frac{k_R p_R t_R}{\phi_R S_R \mu_R L_R^2}\ ,\ \frac{p_R}{\rho_R g_R L_R}\ ,\ \frac{L_{vR}}{C_R T_R}\ ,\ \frac{k_{hR}\,t_R}{\phi_R S_R \rho_R C_R L_R^2}$$

$$\frac{k_{hR} t_R}{\rho_{cR} C_{cR} L_R^2}\ ,\ \frac{\rho_R k_R p_R L_R}{w_R \mu_R}\ ,\ \frac{f_{SR} L_{vR}}{C_R T_R}$$

Table 3: Scaling Groups for Steam Injection
(After Rujol and Boberg[11])

$$\frac{l}{h}\ ,\ \psi\ ,\ \rho_o/\rho_{oi}\ ,\ \rho_w/\rho_{oi}\ ,\ \rho_g/\rho_{oi}\ ,\ \mu_o/\mu_g\ ,\ \mu_o/\mu_w\ ,$$

$$C_o/C_{oi}\ ,\ C_w/C_{oi}\ ,\ H_s/C_r(T_{inj}-T_r)\ ,\ C_r\rho_r/C_{oi}\rho_{oi}\ ,$$

$$C_{ob}\rho_{ob}/C_{oi}\rho_{oi}\ ,\ k_{hw}/k_{ho}\ ,\ k_{hr}/k_{ho}\ ,\ k_{hob}/k_{ho}\ ,\ S_{oi}\ ,\ S_{wi}\ ,$$

$$S_{gi}\ ,\ \phi\ ,\ k_{ro}\ ,\ k_{rw}\ ,\ k_{rg}\ ,\ J\ ,\ \alpha_o/vl\ ,\ kp_c/vl\mu_w\ ,$$

$$k(\rho_o-\rho_g)g/v\mu_o g_c\ ,\ k(\rho_w-\rho_g)g/v\mu_w g_c$$

Table 4: Scaling Groups for Steam Injection with Additives
(After Kimber *et al.*[12])

(1) $\frac{L}{x_{1R}}$

(2) $\frac{H}{x_{2R}}$

(3) $\frac{W}{x_{3R}}$

(4) $\frac{x_{2R}}{x_{1R}}$

(5) $\frac{x_{3R}}{x_{1R}}$

(6) $\frac{\phi_R\, S_{\ell R}\, x_{1R}^2\, \mu_{\ell R}}{t_R\, k_{\ell R}\, p_{\ell R}}$

(7) $\frac{k_{\ell R}\rho_{\ell R}h_{\ell R}p_{\ell R}}{\mu_{\ell R}k_{hwR}T_R}$

(8) $\frac{\rho_{rR}h_{rR}}{\rho_{wR}h_{wR}}$

(9) $\frac{h_{\ell R}}{h_{aR}}$

(10) $\frac{h_{gR}}{h_{aR}}$

(11) $\frac{\mu_{\ell R}k_{gR}}{\mu_{gR}k_{\ell R}}$

(12) $\frac{\mu_{\ell R}k_{aR}}{\mu_{wR}k_{\ell R}}$

(13) $\frac{\rho_{\ell R}}{\rho_{aR}}$

(14) $\frac{\rho_{gR}}{\rho_{aR}}$

(15) $\frac{W_{\ell sR}}{W_{awR}}$

(16) $\frac{W_{gwR}}{W_{awR}}$

(17) $\frac{W_{gsR}}{W_{awR}}$

(18) ϕ_R

(19) $\frac{k_{hcR}}{k_{hwR}}$

(20) $\frac{S_{aiR}}{S_{aR}}$

(21) $\frac{S_{giR}}{S_{aR}}$

(22) $\frac{T_{iR}}{T_R}$

(23) $\frac{P_{iR}}{P_{\ell R}}$

(24) $\frac{p_{prodR}}{p_{\ell R}}$

(25) $\frac{p_{aR}}{p_{\ell R}}$

(26) $\frac{p_{gR}}{p_{\ell R}}$

(27) $\frac{p_{cg\ell R}}{p_{\ell R}}$

(28) $\frac{p_{c\ell aR}}{p_{\ell R}}$

(29) $\frac{\rho_{\ell R}g_R z_R}{p_{\ell R}}$

(30) $\frac{W_{awR}\mu_{aR}}{\rho_{aR}k_{aR}p_{aR}x_{2R}}$

(31) $\frac{A_{injR}}{x_{1R}x_{2R}}$

(32) $\frac{S_{\ell R}\mu_{\ell R}D^{*}_{\ell oR}}{k_{\ell R}p_{\ell R}F_R}$

(33) $\frac{D^{*}_{\ell oR}}{D^{*}_{\ell sR}}$

(34) $\frac{D^{*}_{gsR}}{D^{*}_{\ell sR}}$

(35) $\frac{D^{*}_{gwR}}{D^{*}_{\ell sR}}$

Table 5: Scaling Groups for Cyclic Steam Stimulation (Radial)
(After Niko and Troost[13])

$$\frac{r_e}{h}\ ,\ \frac{\alpha t}{r_e^2}\ ,\ v_o\rho_o C_o r_e/k_{hf}\ ,\ k_{hob} r_e \Delta T/i_s H_s\ ,\ C_w \Delta T/H_s\ ,$$

$$\Delta\rho g k/\mu_o v_o\ ,\ v_o\mu_o/v_b\mu_s\ ,\ q_o\mu_o/\Delta p k r_e\ ,\ \rho_{wi} C_w/\rho_{oi} C_o\ ,$$

$$\rho_r c_r/\rho_{oi} C_o\ ,\ k_{hw} k_{ho}\ ,\ k_{hr}/k_{ho}\ ,\ \phi\Delta S_o\ ,\ kt/\mu_o C_f \phi r_e^2$$

Table 6: Scaling Groups for *InSitu* Combustion
(After Binder *et al.*[14])

$$\frac{l}{h}\ ,\ \frac{\alpha t}{l^2}\ ,\ \frac{vt}{l\phi}\ ,\ \mu_g v/k_v k_{rg} \Delta\rho\ ,\ k_v/k_H$$

Table 7: Scaling Groups for Polymer Flood
(After Islam and Farouq Ali[22])

$$\frac{x_{1R}}{x_{2R}}\ ,\ \frac{x_{1R}}{x_{3R}}\ ,\ \frac{L}{x_{1R}}\ ,\ \frac{W}{x_{3R}}\ ,\ \frac{H}{x_{2R}}\ ,\ \frac{\phi_R\, S_{\ell R}\, x_{1R}^2\, \mu_{\ell R}}{t_R\, k_{\ell R}\, p_{\ell R}}\ ,\ \frac{\rho_{\ell R}\, g_R\, z_R}{p_{\ell R}}\ ,$$

$$\frac{\mu_{\ell R}\, k_{aR}}{\mu_{aR}\, k_{\ell R}}\ ,\ \frac{\rho_{\ell R}}{\rho_{aR}}\ ,\ \frac{W_{apR}}{W_{awR}}\ ,\ \phi_R\ ,\ \frac{S_{aiR}}{S_{aR}}\ ,\ \frac{p_{\ell\ell R}}{p_{\ell R}}\ ,$$

$$\frac{\rho_{rR}\, A_{p\,R}}{S_{aR}}\ ,\ \frac{p_{prod}}{p_{\ell R}}\ ,\ \frac{A_{injR}}{L^2}\ ,\ R\ ,$$

$$B\, C_{ap\,R}\ ,\ \frac{W_{awR}\, \mu_{aR}}{k_{aR}\, p_{aR}\, \rho_{aR}\, L}\ ,\ \frac{S_{aR}\, D^{*}_{apR}\, \mu_{aR}}{k_{aR}\, p_{aR}\, F_R}\ ,\ \frac{D^{*}_{awR}}{D^{*}_{apR}}\ ,$$

$$\frac{C_{apR}}{C_{awR}}$$

Table 8: Scaling Groups for Emulsion Flood-Two-Phase Flow
(After Islam and Farouq Ali[22])

$$\frac{x_{1R}}{x_{2R}}\ ,\ \frac{x_{1R}}{x_{3R}}\ ,\ \frac{L}{x_{1R}}\ ,\ \frac{W}{x_{3R}}\ ,\ \frac{H}{x_{2R}}\ ,\ \frac{\phi_R S_{lR} x_{1R}^2 \mu_{lR}}{t_R k_{lR} p_{lR}}\ ,\ \frac{p_{lR}\, g_R\, z_R}{p_{lR}}\ ,$$

$$\frac{\mu_{lR}K_{aR}}{\mu_{aR}K_{lR}}\ ,\ \frac{\rho_{lR}}{\rho_{aR}}\ ,\ \frac{W_{amR}}{W_{awR}}\ ,\ \frac{W_{lmR}}{W_{lwR}}\ ,\ \phi_R\ ,$$

$$\frac{S_{aiR}}{S_{aR}}\ ,\ \frac{p_{liR}}{p_{lR}}\ ,\ \frac{p_{prod}}{p_{lR}}\ ,\ \frac{A_{injR}}{L^2}\ ,$$

$$\frac{\rho_{aR} g_R L}{p_{aR}}\ ,\ \frac{W_{awR}\mu_{aR}}{K_{aR} p_{aR} \rho_{aR} L}\ ,$$

$$\frac{S_{aR} D^*_{awR} \mu_{aR}}{K_{aR} p_{aR} F_R}\ ,\ \frac{D^*_{loR}}{D^*_{lmR}}\ ,\ \frac{D^*_{awR}}{D^*_{amR}}\ ,$$

$$\frac{C_{loR}}{C_{lmR}}\ ,\ \frac{C_{amR}}{C_{awR}}$$

Table 9: Scaling Groups for Emulsion Flood-Emulsion Miscible in Aqueous Phase Only
(After Islam and Farouq Ali[22])

$$\frac{x_{1R}}{x_{2R}}\ ,\ \frac{x_{1R}}{x_{3R}}\ ,\ \frac{L}{x_{1R}} , \frac{W}{x_{3R}}\ ,\ \frac{H}{x_{2R}}\ ,\ \frac{\phi_R S_{lR} x_{1R}^2 \mu_{lR}}{t_R k_{lR} p_{lR}}\ ,\ \frac{\rho_{lR} g_R z_R}{p_{lR}}\ ,$$

$$\frac{\mu_{lR}K_{aR}}{\mu_{aR}K_{lR}}\ ,\ \frac{\rho_{lR}}{\rho_{aR}}\ ,\ \frac{W_{amR}}{W_{awR}}\ ,\ \phi_R\ ,\ \frac{S_{aiR}}{S_{aR}}\ ,\ \frac{p_{liR}}{p_{lR}}\ ,\ \frac{p_{prod}}{p_{lR}}\ ,\ \frac{A_{injR}}{L^2}\ ,$$

$$\frac{D^*_{awR}}{D^*_{amR}}\ ,\ \frac{C_{amR}}{C_{awR}}\ ,\ \frac{\rho_{aR} g_R L}{p_{aR}}\ ,\ \frac{W_{awR}\mu_{aR}}{K_{aR} p_{aR} \rho_{aR} L}\ ,\ \frac{S_{aR} D^*_{awR} \mu_{aR}}{K_{aR} p_{aR} F_R}$$

Table 10: Scaling Groups for Emulsion Flood - Three-Phase Flow (After Islam and Farouq Ali[22])

$$\frac{x_{1R}}{x_{2R}},\ \frac{x_{1R}}{x_{3R}},\ \frac{L}{x_{1R}},\ \frac{W}{x_{3R}},\ \frac{H}{x_{2R}},\ \frac{\phi_R S_{\ell R} x_{1R}^2 \mu_{\ell R}}{t_R k_{\ell R} p_{\ell R}},\ \frac{\rho_{\ell R} g_R z_R}{p_{\ell R}},$$

$$\frac{\mu_{\ell R} K_{aR}}{\mu_{aR} K_{\ell R}},\ \frac{\mu_{mR} K_{aR}}{\mu_{aR} K_{mR}},\ \frac{\rho_{aR}}{\rho_{\ell R}},\ \frac{\rho_{mR}}{\rho_{aR}},\ \frac{D^{*}_{awR}}{D^{*}_{amR}},\ \frac{D^{*}_{mmR}}{D^{*}_{mwR}},$$

$$\frac{W_{amR}}{W_{awR}},\ \frac{W_{mmR}}{W_{mwR}},\ \phi_R,\ \frac{S_{aiR}}{S_{aR}},\ \frac{S_{\ell iR}}{S_{\ell R}},\ \frac{C_{amR}}{C_{awR}},\ \frac{C_{mwR}}{C_{mmR}},$$

$$\frac{p_{\ell iR}}{p_{\ell R}},\ \frac{p_{miR}}{p_{mR}},\ \frac{p_{prod}}{p_{\ell R}},\ \frac{A_{injR}}{L^2},$$

$$\frac{\rho_{aR} g_R L}{p_{aR}},\ \frac{W_{awR} \mu_{aR}}{K_{aR} p_{aR} \rho_{aR} L},\ \frac{S_{aR} D^{*}_{awR} \mu_{aR}}{K_{aR} p_{aR} F_R}$$

Table 11: Scaling Groups for Foam Injection - Four-Phase Flow (After Islam and Farouq Ali[22])

$$\frac{x_{1R}}{x_{2R}},\ \frac{x_{1R}}{x_{3R}},\ \frac{L}{x_{1R}},\ \frac{W}{x_{3R}},\ \frac{H}{x_{2R}},\ \frac{\phi_R S_{\ell R} x_{1R}^2 \mu_{\ell R}}{t_R k_{\ell R} p_{\ell R}},\ \frac{\rho_{\ell R} g_R z_R}{p_{\ell R}},$$

$$\frac{\mu_{\ell R} K_{aR}}{\mu_{aR} K_{\ell R}},\ \frac{\mu_{\ell R} K_{fR}}{\mu_{fR} K_{\ell R}},\ \frac{\mu_{gR} K_{aR}}{\mu_{aR} K_{gR}},$$

$$\frac{\rho_{\ell R}}{\rho_{aR}},\ \frac{\rho_{fR}}{\rho_{aR}},\ \frac{\rho_{gR}}{\rho_{aR}},\ \frac{A_{injR}}{L^2},\ \frac{C_{\ell oR}}{C_{\ell sR}},\ \frac{C_{asR}}{C_{awR}},\ \frac{C_{fsR}}{C_{fgR}},\ \frac{C_{fwR}}{C_{fgR}},$$

$$\frac{W_{asR}}{W_{awR}},\ \frac{W_{fsR}}{W_{fgR}},\ \frac{W_{\ell sR}}{W_{\ell oR}},\ \frac{W_{fgR}}{W_{fwR}},\ \phi_R,$$

$$\frac{S_{\ell iR}}{S_{\ell R}},\ \frac{S_{aiR}}{S_{aR}},\ \frac{S_{giR}}{S_{gR}},\ \frac{D^{*}_{\ell oR}}{D^{*}_{\ell sR}},\ \frac{D^{*}_{awR}}{D^{*}_{asR}},\ \frac{D^{*}_{fwR}}{D^{*}_{fsR}},\ \frac{D^{*}_{fgR}}{D^{*}_{fsR}},$$

$$\frac{p_{\ell iR}}{p_{\ell R}},\ \frac{p_{fiR}}{p_{fR}},\ \frac{p_{giR}}{p_{gR}},\ \frac{p_{prod}}{p_{\ell R}},$$

$$\frac{\rho_{aR} g_R L}{p_{aR}},\ \frac{W_{awR} \mu_{aR}}{K_{aR} p_{aR} \rho_{aR} L},\ \frac{S_{aR} D^{*}_{awR} \mu_{aR}}{K_{aR} p_{aR} F_R}$$

Table 12: Scaling Group for Foam Injection - Three-Phase Flow
(After Islam and Farouq Ali[22])

$$\frac{x_{1R}}{x_{2R}}, \frac{x_{1R}}{x_{3R}}, \frac{L}{x_{1R}}, \frac{w}{x_{3R}}, \frac{H}{x_{2R}}, \frac{\phi_R\, S_{fR}\, x_{1R}^2\, \mu_{fR}}{t_R\, k_{fR}\, p_{fR}}, \frac{\rho_{fR}\, g_R\, z_R}{p_{fR}},$$

$$\frac{\mu_{fR} K_{aR}}{\mu_{aR} K_{fR}}, \frac{\mu_{fR} K_{fR}}{\mu_{fR} K_{fR}}, \frac{\rho_{fR}}{\rho_{aR}}, \phi_R, \frac{\rho_{fR}}{\rho_{aR}}$$

$$\frac{A_{injR}}{L^2}, \frac{W_{asR}}{W_{awR}}, \frac{W_{fsR}}{W_{foR}}, \frac{S_{gR}}{S_{fR}}, \frac{D^{*}_{fwR}}{D^{*}_{fsR}}, \frac{C_{foR}}{C_{fsR}}, \frac{C_{asR}}{C_{awR}}$$

$$\frac{S_{aiR}}{S_{aR}}, \frac{p_{fiR}}{p_{fR}}, \frac{p_{fiR}}{p_{fR}}, \frac{p_{prod}}{p_{fR}},$$

$$\frac{\rho_{aR} g_R L}{p_{aR}}, \frac{w_{awR} \mu_{aR}}{K_{aR} p_{aR} \rho_{aR} L}, \frac{S_{aR} D^{*}_{awR} \mu_{aR}}{K_{aR} p_{aR} F_R}, \frac{D^{*}_{foR}}{D^{*}_{fsR}}, \frac{D^{*}_{awR}}{D^{*}_{asR}}$$

Table 13: Scaling Criteria for Immiscible CO_2 Injection
(After Rojas[28])

$$L/W,\ L/H, \frac{k_{rg}\, \mu_o}{k_{ro}\, \mu_w}, \frac{k_{rw}\, \mu_o}{k_{ro}\, \mu_w}, \frac{g\, k\, \Delta\rho_{og}}{v\, \mu_g},$$

$$\frac{g\, k\, \Delta\rho_{wo}}{v\, \mu_w}, \frac{\sigma_{go}\sqrt{k\phi}}{L\, \mu_g\, v}, \frac{\sigma_{ow}\sqrt{k\phi}}{L\, \mu_w\, v}, \frac{D_{goy}\, L}{w^2\, |v|},$$

$$\frac{D_{gwy}\, L}{w^2\, |v|}, \frac{D_{goy}}{D_{gox}}, \frac{L}{w}, \frac{D_{goz}}{D_{gox}}, \frac{L}{H}, \frac{D_{gwy}}{D_{gwx}}\frac{L}{w},$$

$$\frac{D_{gwz}}{D_{gwx}}\frac{L}{H}, \frac{\rho_g\sqrt{k}\; v}{\mu_g}, \frac{\rho_w\sqrt{k}\; v}{\mu_w}, \frac{\dot{v}_w}{\dot{v}_g}, \phi,$$

$$M, k_{rg}, k_{ro}, k_{rw}, J_{go}, J_{wo},$$

$$\frac{dJ}{dS_g}, \frac{dJ}{dS_w}$$

Table 14: Scaling Groups for Immiscible CO_2 Injection with Partial Equilibrium (After Lozada and Farouq Ali[14])

$$\phi_R, \frac{\phi_R S_{\ell R} \mu_{\ell R} x_{1R}^2}{t_R k_{\ell R} p_{\ell R}}, \frac{L}{x_{1R}}, \frac{H}{x_{2R}}, \frac{W}{x_{3R}}, \frac{x_{2R}}{x_{1R}}, \frac{x_{3R}}{x_{1R}}, \frac{\rho_{\ell R} g_R z_R}{p_{\ell R}}, \frac{\rho_{gR}}{\rho_{\ell R}},$$

$$\frac{\rho_{aR}}{\rho_{\ell R}}, \frac{\mu_{\ell R}}{\mu_{gR}}, \frac{k_{gR}}{k_{\ell R}}, \frac{\mu_{\ell R} k_{wR}}{\mu_{wR} k_{\ell R}}, S_{\ell R}, \frac{S_{\ell i}}{S_{\ell R}}, \frac{S_{aR}}{S_{\ell R}}, \frac{S_{gR}}{S_{\ell R}}, \frac{p_{c\ell aR}}{p_{\ell R}}, \frac{p_{cg\ell R}}{p_{\ell R}},$$

$$\frac{p_{\ell i}}{p_{\ell R}}, \frac{p_{ai}}{p_{\ell R}}, \frac{p_{aR}}{p_{\ell R}}, \frac{p_{gR}}{p_{\ell R}}, \frac{p_{prod}}{p_{\ell R}}, \frac{\phi_R S_{\ell R} \mu_{\ell R}}{k_{\ell R} p_{\ell R}}, D_{LCO_2,\ell R}, \frac{D_{TCO_2,\ell R}}{D_{LCO_2,\ell R}},$$

$$\frac{D_{LCO_2,gR}}{D_{LCO_2,\ell R}}, \frac{D_{TCO_2,gR}}{D_{LCO_2,\ell R}}, \frac{D_{LCO_2,aR}}{D_{LCO_2,\ell R}}, \frac{D_{TCO_2,aR}}{D_{LCO_2,\ell R}}, \frac{D_{Lo,\ell R}}{D_{LCO_2,\ell R}}, \frac{D_{To,\ell R}}{D_{LCO_2,\ell R}}, \frac{D_{Lw,aR}}{D_{LCO_2,\ell R}},$$

$$\frac{D_{Tw,aR}}{D_{LCO_2,\ell R}}, \frac{W_{CO_2 R} \mu_{gR}}{x_{2R} \rho_{gR} k_{gR} p_{gR}}, \frac{A_{injR}}{x_{1R} x_{2R}}, \frac{W_{aR}}{W_{CO_2R}}$$

$$N_{CO_2,\ell gR}, \frac{\mu_{\ell R} x_{1R}^2}{C_{CO_2,\ell R} \rho_{\ell R} k_{\ell R} p_{\ell R}}, \frac{N_{CO_2,g\ell R}}{N_{CO_2,\ell gR}}, \frac{N_{CO_2,\ell aR}}{N_{CO_2,\ell gR}}, \frac{N_{CO_2,a\ell R}}{N_{CO_2,\ell gR}},$$

$$C_{CO_2,\ell R}, \frac{C_{CO_2,aR}}{C_{CO_2,\ell R}}, \frac{C_{o,\ell R}}{C_{CO_2,\ell R}}, \frac{C_{w,aR}}{C_{CO_2,\ell R}}, \frac{C_{CO_2,gR}}{C_{CO_2,\ell R}}$$

Table 15: Scaling Groups for Hot Miscible Displacement (Single Phase) (After Greenkorn *et al.*[30])

$$\frac{l}{h}, \frac{vt}{h}, \frac{vh\rho}{\mu}, \frac{\Delta p}{\rho v^2}, \frac{v^2}{hg}, \frac{\mu}{\rho D}, \frac{h^2}{k},$$

$$k_h T/d\rho v^3, \ \beta T, \ cT/v^2$$

10

HEATS OF COMBUSTION OF LIGHT AND HEAVY OILS

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ABSTRACT

A precision automatic adiabatic rotating bomb calorimeter was used to measure the heats of combustion of light and heavy oils from Syncrude Canada, Xinjiang and Liaohe oil fields. The predicted values obtained from our previously proposed empirical correlations were compared with the data. The results indicated that the correlation was suitable for engineering applications in calculating the heats of combustion.

INTRODUCTION

Heats of combustion of heavy and light oils are needed for the heat balance calculations in industrial processes. Due to the complex structures of the crude oils, no empirical correlation has existed which can calculate the heats of combustions of crude oils as accurately as those correlations for pure compounds. Also, data of this kind was lacking. As a result, a precision automatic adiabatic rotating calorimeter having a platinum-lined bomb was used (1) to measure the heats of combustion of several heavy and light oils and cokes. Subsequently, with this data, an empirical correlation was established. The purposes of this work were, first, to provide heats of combustion database for our heavy oil fields and secondly to use the data to verify the empirical correlation proposed previously. Using the same apparatus, the heats of combustion of eight light oils from Sycrude Canada and five heavy oils from Xinjingand Liaohe oil fields were measured.

EXPERIMENTAL

Material

Eight light oil samples provided by Sycrude Canada were used for calorimetric measurement without further treatment. Five heavy oil samples were taken from Xinjiang and Liaohe oil fields. Before measurement, the samples were dried in a vacuum oven for 8 hours and then left in a desiccator for a few days. Results of the the elemental analysis are given in Table 1.

Apparatus and Procedures

A precision automatic adiabatic rotating platinum-lined bomb calorimeter was used. All the internal parts are made of platinum. Detailed experimental procedures are given in references (2) and (3). Temperature was measured using HP 2304A Quartz Thermo- meter with a resolution of 0.0001 °C.

For each run, 10 ml of distilled water was added into the bomb. While maintaining the air pressure at 1 atm, the bomb was pressurized to 35 atms by charging it with oxygen of 99.99% purity. The calorimeter was filled with 4000 grams water. To avoid the vaporization of the light oils which may cause incomplete combustion, all the light oil samples were kept in the polyethlene ampoule vials during runs. The samples were then burned with a fuse of cotton thread. The heats of combustion of the polyethylene and cotton thread were measured to be 46409 and 16289 J.g^{-1}, respectively.

The energy equivalent of the calorimeter was calibrated by the burning thermochemical standard benzoic acid (U.S. National Bureau of Standards, 39i) whose heat of combustion at the certified conditions is 26434±1 Jg^{-1}. The energy equivalent was measured to be 17903±3 J deg^{-1}.

The final bomb solutions were analyzed for nitric acid and sulfur with 0.5% precision.

RESULTS AND CONCLUSIONS

Results of the measurements are presented in Table 2. The following idealized combustion reaction was used to calculate the standard dUc$^{\circ}$:

$$C_aH_bO_cS_dN_{e(l)} + (a+d+b/4-c/2)\,O_{2(g)}$$

$$=(a)\,CO_{2(g)} + (b/2)\,H_2O_{(l)} + (d)S\,O_{2(g)} + (e/2)\,N_{2(g)}$$

where the reactants and products are in their thermodynamic standard states at 298.15 K.

Based on the elemental analysis in Table 1, the heats of com- bustion of the oils were calculated using the following empirical equation:

$$-dUc^0 = 34.73(C\%) + 116.96(H\%) + 15.05(S\%) - 19.27((N+O)\%)$$

where dUc^0 is in K J/g. Comparisons of the calculated and experimental values are given in Table 3. As can be seen, for most of the oils, the agreements are within 1%. Larger errors (2-3%), however, were found for volatile oils. This may be partially due to the experi- mental errors associated with the data. In general, the high oil volatility causes problems in measuring the heats of combustion and elemental analysis. Overall, the results indicated that the empirical correlation was suitable for calculating the heats of combustion of bitumen, oil shales, heavy and light oils. For engineering purposes, the correlation provides a simple and reliable method to estimate the heats of combustion of different oils.

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Table 1
Results of Element Analysis

Sample	C(%)	H(%)	S(%)	(N+O)(%)
Treated gas oil 15 x 008 (1)	87.46	11.91	0.28	0.35
Treated gas oil 15 x 008 (2)	87.51	11.78	0.35	0.36
Synthetic crude oil 200,000 (1)	87.36	12.05	0.42	0.17
Synthetic crude oil 200,000 (2)	86.90	12.56	0.36	0.18
Treated naphtha 13 x 005 (1)	85.59	13.38	0.15	0.88
Treated naphtha 13 x 005 (2)	85.80	13.21	0.17	0.82
Diluent naphtha to plant 6060 Oil (1)	83.45	13.79	0.29	2.32
Diluent naphtha to plant 6060 Oil (2)	83.70	13.92	0.21	2.03
Xinjiang heavy oil (1)	86.37	12.14	0.30	1.19
Xinjiang oil (2)	85.62	12.25	0.30	1.81
Xinjiang oil (3)	86.89	12.32	0.28	0.51
Liaoho oil (1)	85.66	11.55	0.30	0.89
Liaoho oil (2)	87.72	11.36	0.27	0.76

Table 2
Heats of Combustion of Light and Heavy Oils

Sample	$-\Delta U_c^\circ$ (KJ. g^{-1})
Treated gas oil 15 x 008 (1)	44.50 ± 0.02
Treated gas oil 15 x 008 (2)	44.52 ± 0.08
Synthetic crude oil 200,000 (1)	45.81 ± 0.05
Synthetic crude oil 200,000 (2)	45.54 ± 0.03
Treated naphtha 13 x 005 (1)	44.71 ± 0.01
Treated naphtha 13 x 005 (2)	44.65 ± 0.04
Diluent naphtha to plant 6060 011 (1)	46.11 ± 0.02
Diluent naphtha to plant 6060 011 (2)	46.41 ± 0.06
Xinjiang heavy oil (1)	43.53 ± 0.04
Xinjiang oil (2)	44.29 ± 0.06
Xinjiang oil (3)	44.42 ± 0.06
Liaoho oil (1)	43.51 ± 0.13
Liaoho oil (2)	43.22 ± 0.03

Table 3
Comparison of the Calculated and Experimental Heats of Combustion

Sample	Experimental (K j/g)	Calculated (K j/g)	Deviation
Coal(4)	40.71	41.11	-0.40
Coal(4)	41.59	42.03	-0.44
Oil Shale(6)	39.83	38.97	0.86
Oil Shale(6)	39.54	40.29	-0.75
Coke(1)	33.53+0.12	33.47	0.06
Coke(1)	29.70+0.18	29.67	0.03
	42.47	41.98	0.49
	42.68+0.12	42.70	-0.02
	41.46+0.08	41.49	-0.03
	40.55+0.08	40.25	0.3
	41.60+0.09	41.66	-0.06
	37.79+0.10	37.77	0.02
	36.82+0.10	37.22	-0.40
Treated Gas Oil 15x008(2)	44.52+0.08	44.15	0.37
Treated Naphtha 13x005 (2)	44.65+0.04	44.89	-0.24
Synthetic crude oil 200,000(2)	45.54+0.03	45.10	0.44
Diluent Naphtha to Plan 6060 (2)	46.41+0.06	45.15	1.26
Xinjiang heavy (1) oil(1)	43.53+0.04	44.01	-0.48
Xinjiang Oil(2)	44.29+0.06	43.96	0.27
Xinjiang Oil(3)	44.42+0.06	44.54	-0.12
Liaohe Oil(1)	43.51+0.13	43.13	0.37
Liaohe Oil(2)	43.22+0.03	43.64	-0.42

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SLANT AND DIRECTIONAL DRILLING

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ABSTRACT

Vertical or conventional drilling practices include the technique of directional drilling. During recent years technical developments have added slant hole drilling as a supplementary method that enhances directional drilling capabilities.

This paper discusses, in part, the reasons for slant and/or directional drilling and the factors that are considered in choosing either approach.

The major portion of the paper presents as examples of the foregoing, the technical summary from two unique projects drilled in western Canada.

The first project is a combination of ten slant and thirteen conventional directional oil wells drilled from one pad, at Wolf Lake, Alberta.

The second project is a single gas well drilled at Brooks, Alberta, that required extreme horizontal displacement.

INTRODUCTION

Traditionally, the most economical way to drill an oil or gas well has been to spud the well vertically at surface and drill as straight as possible to the required target. This practice is still the most cost efficient method but other factors may require the employment of directional drilling and/or slant drilling.

When conventional directional drilling is needed it requires starting a well in the usual vertical mode and by using bottom hole assemblies (BHA) or more recently, mud motors, deviating the well at the appropriate angle required to reach the target. This procedure increases the measured length of the well and coupled with the use of specialized equipment, results in higher drilling costs.

Slant hole drilling causes the well to be started at an angle , to a maximum of 45°, and by using directional tools the well may be drilled straight to target, or deviated as required. As with conventional directional drilling, this procedure results in a measured depth that is greater than the true vertical depth (TVD) . Again, specialized equipment is required and drilling costs are relatedly higher.

This paper identifies the most common reasons for both slant and directional drilling and provides for discussion, two case studies that demonstrate the latest accomplishments in the application of this technology.

CONSIDERATIONS FOR SLANT AND/OR DIRECTIONAL DRILLING

In many cases the actual physical and economic conditions present may prevent the use of conventional drilling practices and can necessitate a consideration for slant and/or directional drilling because of the following:

Directional Drilling

❑ *A. Reaching Beneath an Obstruction (Fig. 1)*

Obstructions most often encountered include lakes, rivers, residential development and topographical constraints. Productive farmland also requires that interference be minimized.

❑ *B. Consolidating Facilities (Fig. 2)*

By consolidating surface facilities using multiwell drilling pads the emphasis is on the improved economics and cost savings that result by minimizing land use, surface gathering systems andproject maintenance during the producing life of the reservoir.

❑ *C. Production Improvement (Fig. 3 & 4)*

In changing the angle of the hole, the length of the pay zone can be increased proportionately to the angle chosen. Ocelot Industries Ltd. indicate a penetration at 45° increases production by a factor of 1.4 and a penetration of 70° by a factor three times the normal vertical rate.

❑ *D. Wild Well Control*

Directional drilling has been used successfully to provide pressure relief to out of control wells. This procedure requires drilling a relief well, from a safe distance, to intersect the pressure zone in question.

❑ *E. Depth and Displacement*

Although there are numerous theories on the subject, the Canadian experience suggests that for shallower depths, up to 1500 m TVD, a maximum build angle of $4^{\circ}/5^{\circ}$ per 30 m should be maintained. Build rates in excess of this increase the risk of problem doglegs.

■ Slant (Angle) Drilling

The factors that suggest directional drilling techniques may also form a requirement for slant drilling as the following items more specifically address:

❑ *A. Wellbore Curvature (Fig. 5)*

A slant well drilled straight to target, or a slant well that increases its original inclination has less wellbore curvature than a comparable vertically spud well. The objective is to reduce production interference from doglegs and other problems associated with high curvature wells.

❑ *B. Horizontal Displacement (Fig. 6)*

By starting a well at angles of up to 45° and then increasing that angle, horizontal displacements of over 100 m have been achieved at true vertical depths of 500 m. Additionally, wellbore curvature has been minimized.

❑ *C. Pad Drilling (Fig. 2)*

The added horizontal displacement provided by slant hole drilling has been used as a supplement to conventional directional drilling to increase the number of wells drilled from one pad.

❑ *D. Depth and Displacement*

Presently there is no identifiable standard angle at which slant drilling becomes necessary. The variables involved in arriving at such determinations include, true vertical depth, horizontal displacement required, geological formation, well bore curvature and whether the well is oil or gas. However, Canadian companies generally support the approach that a well requiring a straight hole angle from surface to target of 20° or greater, is a potential slant project.

WOLF LAKE & GRAND PRIX DRILLING PROJECTS

The following two case studies are presented for discussion as examples of practical, state of the art, slant and directional drilling, as utilized in Canada. Both projects are unique in the implementation of this technology and reflect the considerations for slant and directional drilling already identified in this paper.

Additionally, the summarized operational data provided may act as benchmarks to guide discussion in considering similar, future projects.

■ Equipment Utilized (Fig . 7)

Although there are three classes of the Sierra type drilling rig, both of the projects in this paper were drilled with a model 5000 (rated to 1700 m). The other classes are the model 3500 (rated to 1200 m) and the model 7500 (rated to 2500 m). All models share the same characteristics and are similar in appearance but differ in capacity.

The two rigs featured in this paper, Sierra Rig #2, and Sierra Rig #5, are a trailer mounted design that allows for maximum portability and they can also be outfitted with self moving devices for use on pad or multiwell projects. Like all of the Sierra class equipment, both are conventional drilling rigs, capable of drilling in the vertical position but their masts may also be set at 1 $1/2^{\circ}$ incremental angles to a maximum of 450 from vertical.

Each of the rigs has a Static Hook Load rating of 250,000 lbs. at all angles, including 45°. Additionally, the rigs handle single stands of drill pipe and utilize a hydraulic pipe arm for making connections and horizontal racking. Incorporated into the masts are power swivels that travel on tracks and therefore eliminate the traditional rotary table, rathole, mousehole, spinning chain and need for a derrickman.

PROJECT #1 - WOLF LAKE

Introduction

Wolf Lake is located in the north east part of the province of Alberta in Western Canada. B.P. Canada Inc. have extensive land holdings in the area, which are recognized as one of the world's richest heavy oil deposits. As part of their ongoing development program a project was engineered to drill 23 wells from one pad. (Fig. 8 & 9)

The plan required ten slant wells of which six wells were spud at 30°, two at 29°, one at 27° and one at 26° The other thirteen wells were started vertically and drilled directionally.

PLANNING CRITERIA

The engineering of the project established the following key points as objectives.

True Vertical Depth	414 m
Measured Depth Max. for slant wells	567 m
Measured Depth Max. for direct wells	523 m
Drilling Target Primary	13.5 m x 6 m
Secondary	27 m x 12 m
Maximum Spud Angle	30°
Maximum Angle at Target	45°
Angle Build, Maximum	4°/30 m
Dogleg Severity, Maximum	5°/30 m

Drilling Criteria

The operational portion of the program was guided by the following objectives.

Surface Hole Diameter	343 mm (13 1/2")
Main Hole Diameter	251 mm (9 7/8")
All Wells Logged	
Gel Chem Mud	
Case 3 Slant Wells	273 mm
Case 3 Vertical Wells	273 mm

Directional Control (Fig. 10)

Directional control and supervision was provided by Sperry Sun Canada Ltd., and included the use of directionally equipped mud motors.

The motors were oriented to build and maintain drift angle as well as make minor azimuth adjustments. When both the angle and direction requirements to achieve the target parameters had been met, the drill string was rotated slowly to negate the effects of the deflecting action of the motor.

Each well was drilled with one bottom hole assembly. No trips were necessary for assembly changes and penetration rates were considerably higher than with conventional rotary assemblies because of the mud motors high rotary speed (300 - 500 RPM).

Central System (Fig. 11)

The multiwell purpose of the drilling location required that a "Central" Mud system be incorporated to further benefit the overall economics of the project. The configuration used allowed the centralized mud system, generator, boiler and mud pump house to remain in one location on the pad for the duration of the drilling. The mud system itself, was comprised of a desander, desilter, desilter mud slinger and centrifuge.

A flexible utilidor connecting to the drilling rig allowed for fluids transfer during drilling and enhanced rig moves from well to well.

Wolf Lake - Summary

- ☐ *A. The six 30° Slant holes required a total of 12.46 days to drill providing an average of 2.07 days per hole (Spud to Rig Release S. to R.R.)*
- ☐ *B. The two 29° slant holes required a total of 4.30 days to drill providing an average of 2.15 days (S. to R.R.).*
- ☐ *C. The 27° slant hole was drilled in 2.6 days (S. to R.R.)*
- ☐ *D. The 26° slant hole was the first hole drilled on the pad and including long move and first hole rig-up was drilled in 2.80 days (S. to R.R.)*
- ☐ *E. The overall average spud to rig release time on the 10 slant wells was 2.2 days per well.*
- ☐ *F. The thirteen conventional directional holes required a total of 24.10 days to drill. This included two wells that required cutting a total of 9 cores. The average drilling time for each hole was 1.85 days.*
- ☐ *G. The program was drilled under mid-winter conditions with the first well being spud on December 6, 1986 and final rig release on February 1, 1987.*
- ☐ *H. The program was approached as a pilot project for future reference, consequently the drilling schedule was excessively budgeted to take approximately 120 days. The actual drilling days required however were only 46.*

☐ *I. All primary targets were achieved.*

PROJECT #2 - GRAND PRIX

Introduction

Project #2 was a shallow gas well drilled for Grand Prix Natural Gas Ltd. in southern Alberta near the town of Brooks. Located in rich, irrigated farmland, direct vertical access to the target was not permissible. (Fig. 12 & 13).

The alternative chosen was to spud the well at an angle of 45° and by using directional tools, build angle to a maximum of 78° to reach the target area. The well was to be drilled by Sierra Rig #2.

Planning Criteria

True Vertical Depth	514.15 m
Measured Depth	1400 m
Horizontal Displacement	1281 m
Maximum Spud Angle	45°
Surface Hole Size	291 mm
Surface Hole Depth	181 m (MD) 123 m (TVD)
Surface Casing	178 mm H40 to 181 m (MD)
Maximum Angle Build	4°/30 m
Maximum Angle Reached	78 . 25°

Grand Prix Summary (Fig. 14 &15)

☐ *A. The use of downhole motors was not required on this project, instead experience gained on previous and similar projects allowed the employment of more conventional and less costly bottom hole asemblies (BHA) .*

☐ *B. The well was drilled under budget and inside of the expected time schedule, with a total elapsed time from spud to rig release of 5.42 days.*

☐ *C. This well is believed to be the first well achieving such great horizontal displacement at such shallow depth.*

CONCLUSIONS

1. The adaptation of slant/directional drilling to land based projects is relatively recent, with the vast majority of those wells (approx. 800) being drilled within the last 7 to 8 years. In that period the technology has shown considerable progress in establishing both technical capability and economic efficiency.

2. The acceptance of slant/directional drilling as a viable alternative to certain requirements has acted as a catalyst in prompting accelerated development of support technology e.g. service rigs and equipment, production and pumping equipment, directional technology, completion procedures.

3. The major uses for this technology are seen in the shallow depth heavy oil areas where the numerous wells required are conducive to the multiwell drilling pad approach, and to those projects requiring considerable horizontal displacement, also, at shallow depths.

4. Future development of slant drilling rigs is expected to result in equipment capable of operating in the 4000m to 5000m TVD range. Use of such technology, 3 yrs. to 5 yrs. away, is seen almost exclusively for remote regions i.e. Canadian Arctic, inaccessible jungle areas.

5. As use of the slant technology continues, a requirement for an increased number of drilling rigs capable of operating in either the vertical or slant mode seems practical.

ACKNOWLEDGMENT

The authors wish to recognize the contributions made to this paper by B.P. Canada Inc., Grand Prix Natural Gas Ltd., Computalog Gearhart Ltd., Sperry Sun Ltd.

Figure 1
Tilley "B" Reservoir Slant Hole Project

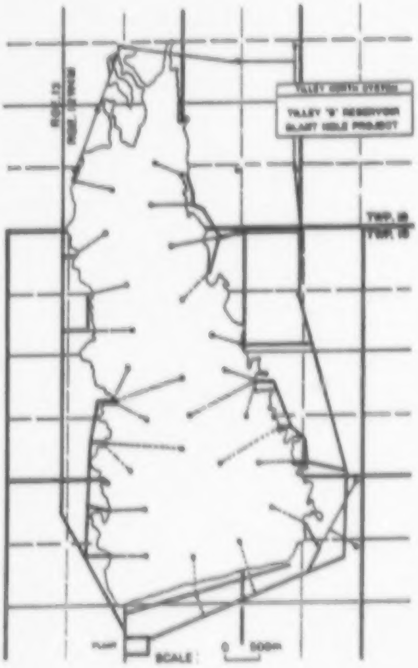

TILLEY "B" RESERVOIR
SLANT HOLE PROJECT
SCALE
0
500m

Figure 2
Pad Drilling Layout

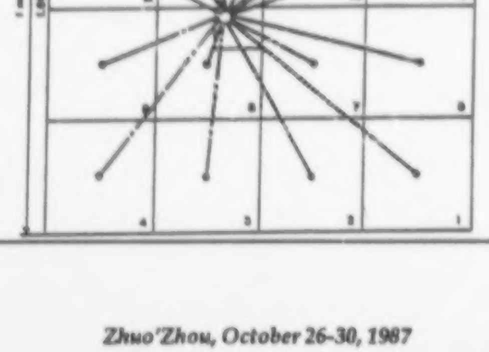

1 mile
7
9
4
3
2
1

Figure 3
Typical 45° Well

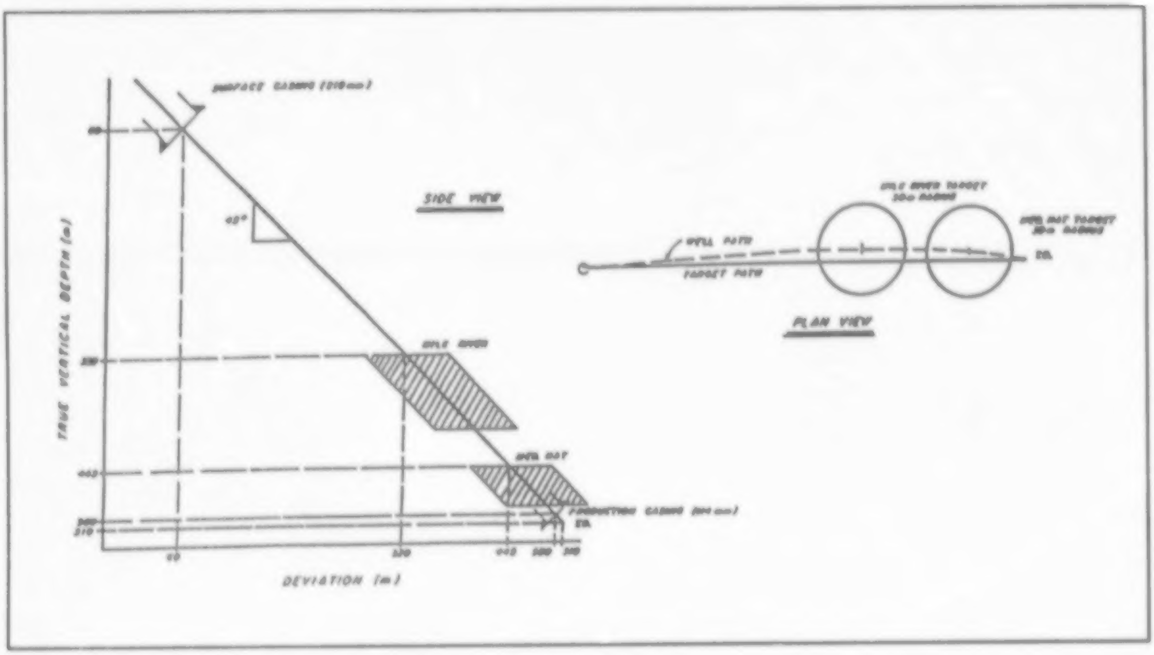

SURFACE CASING
SIDE VIEW
45°
TRUE VERTICAL DEPTH (m)
PRODUCTION CASING
T.D.
DEVIATION (m)
WELL PATH
TARGET PATH
T.D.
PLAN VIEW

Figure 4
Typical 70° Well

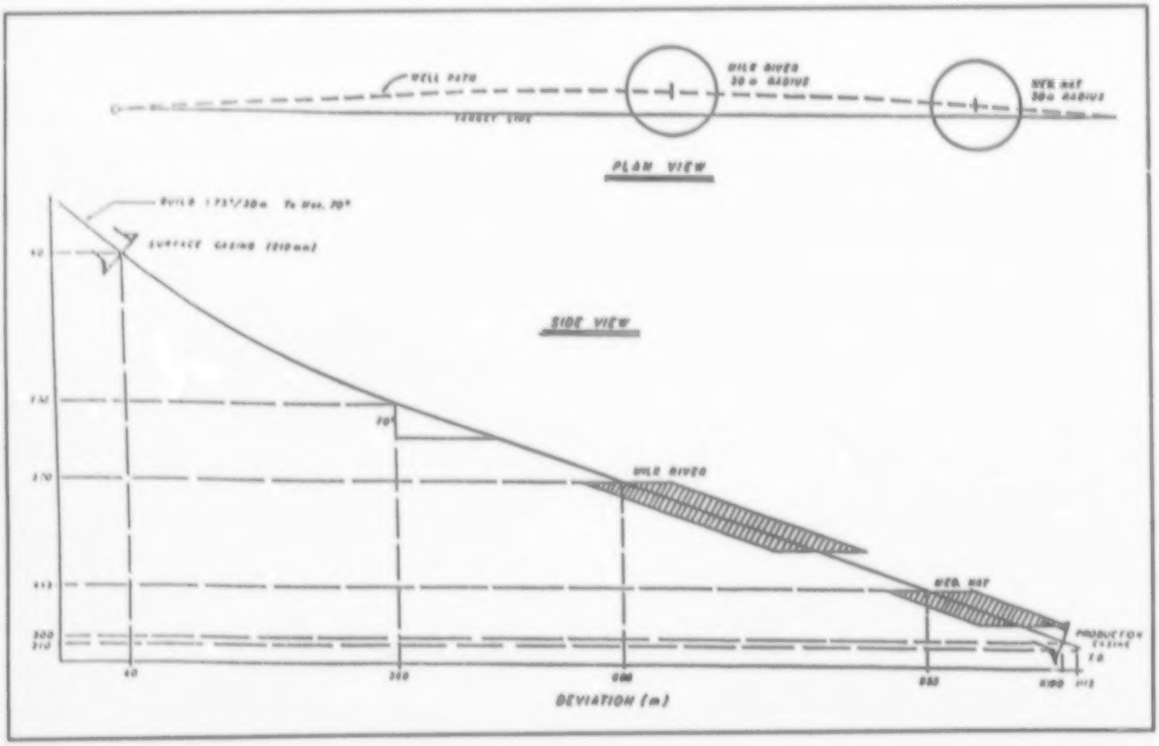

WELL PATH
TARGET LINE
30 m RADIUS
30 m RADIUS
PLAN VIEW
SURFACE CASING
SIDE VIEW
70°
PRODUCTION CASING
T.D.
DEVIATION (m)

Figure 5
Cross-Section of Slant and Directional Wells

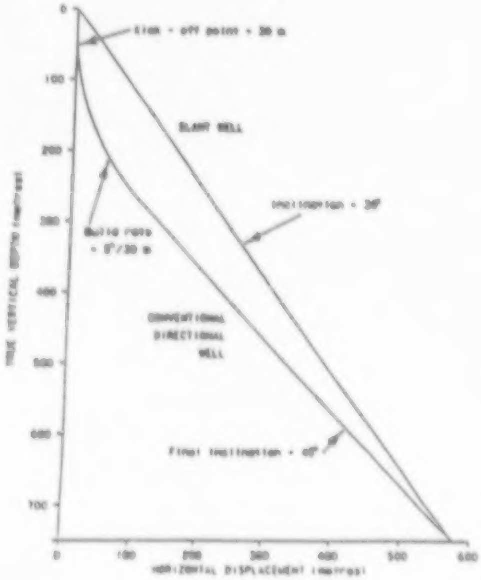
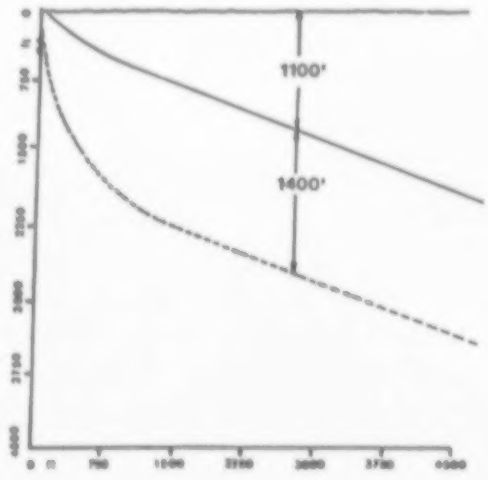


Figure 6
Comparison of Slant Deviated vs Conventional Deviated



1foot = .3048meters

Figure 7
Sierra Drilling Rig

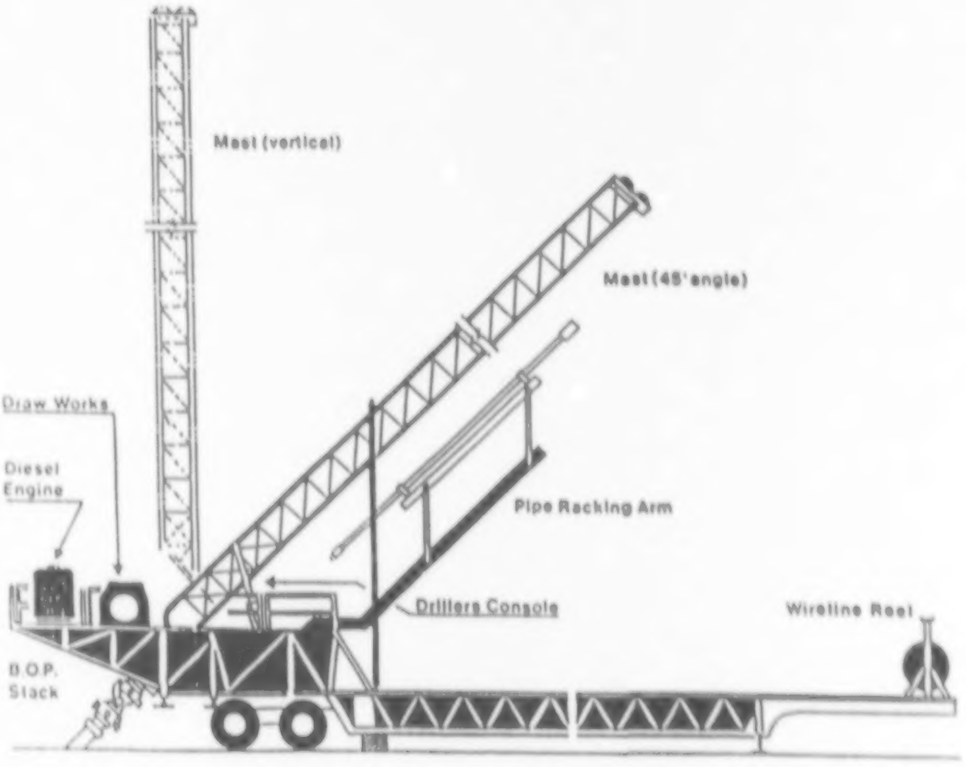

Mast (vertical)
Mast (45°angle)
Draw Works
Diesel Engine
Pipe Racking Arm
Drillers Console
Wireline Reel
B.O.P. Stack

Figure 8
20 Well Pad + 2 Test Wells

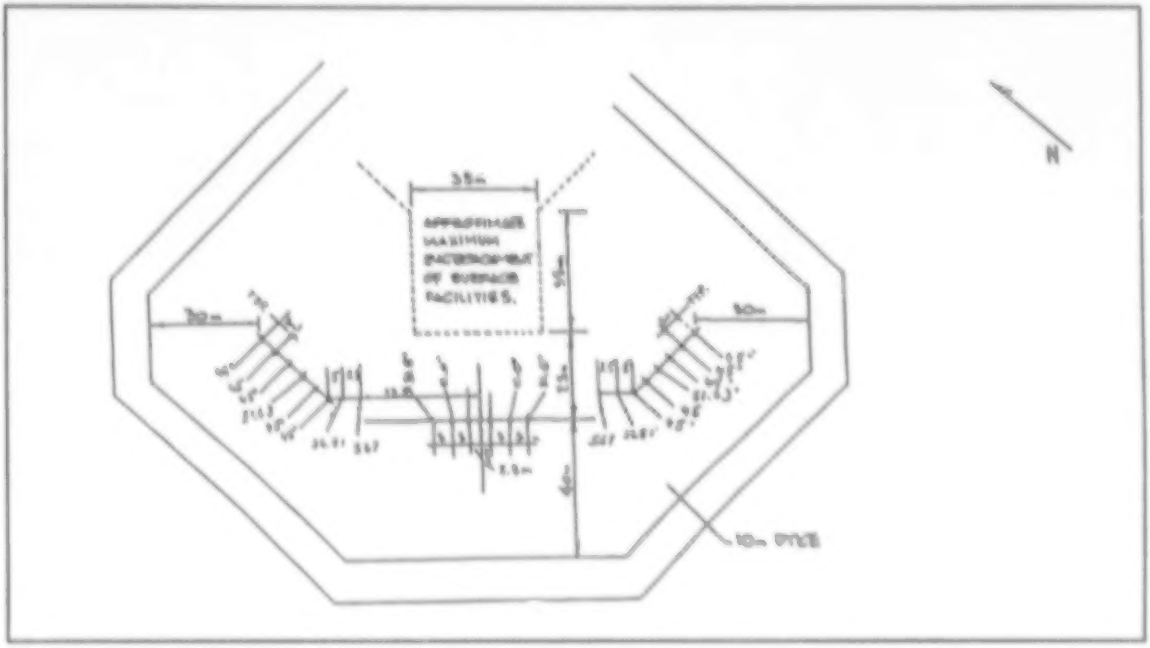

N
35m
APPROXIMATE
MAXIMUM
ENCROACHMENT
OF SURFACE
FACILITIES.
30m
30m
2.5m
10m DYKE

Figure 9
"B" Unit Pad

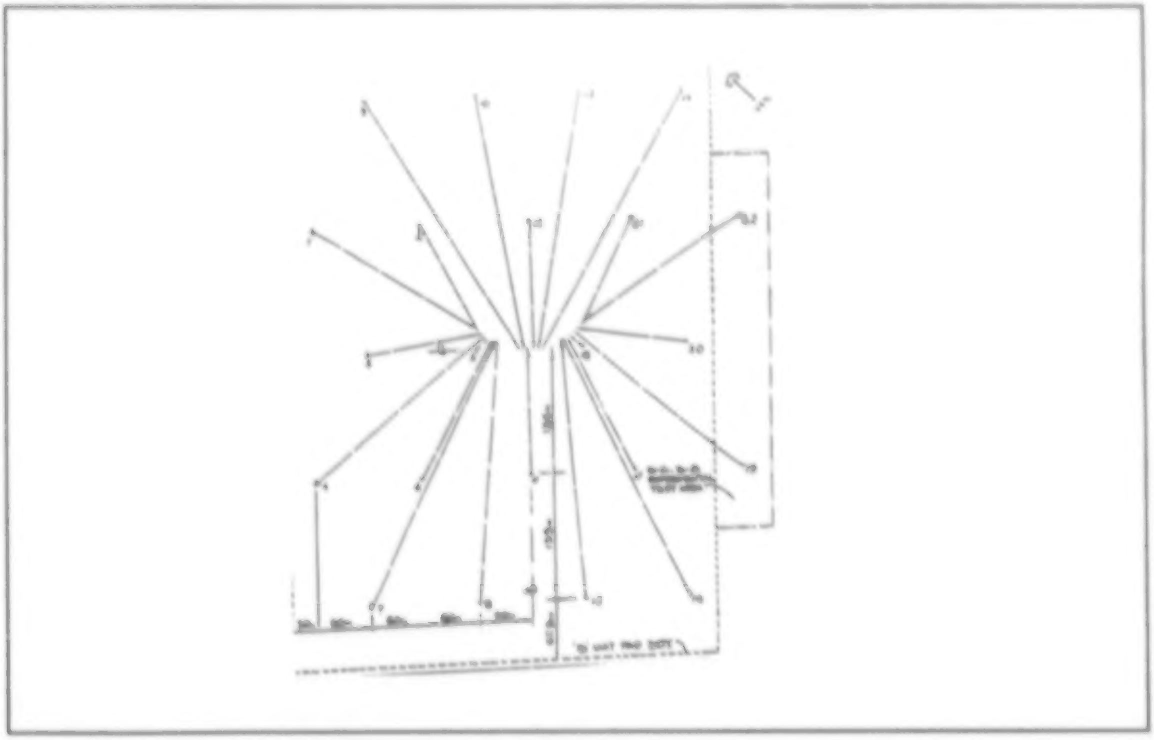


Figure 10
NL Sperry-Sun Mud Motor Assembly

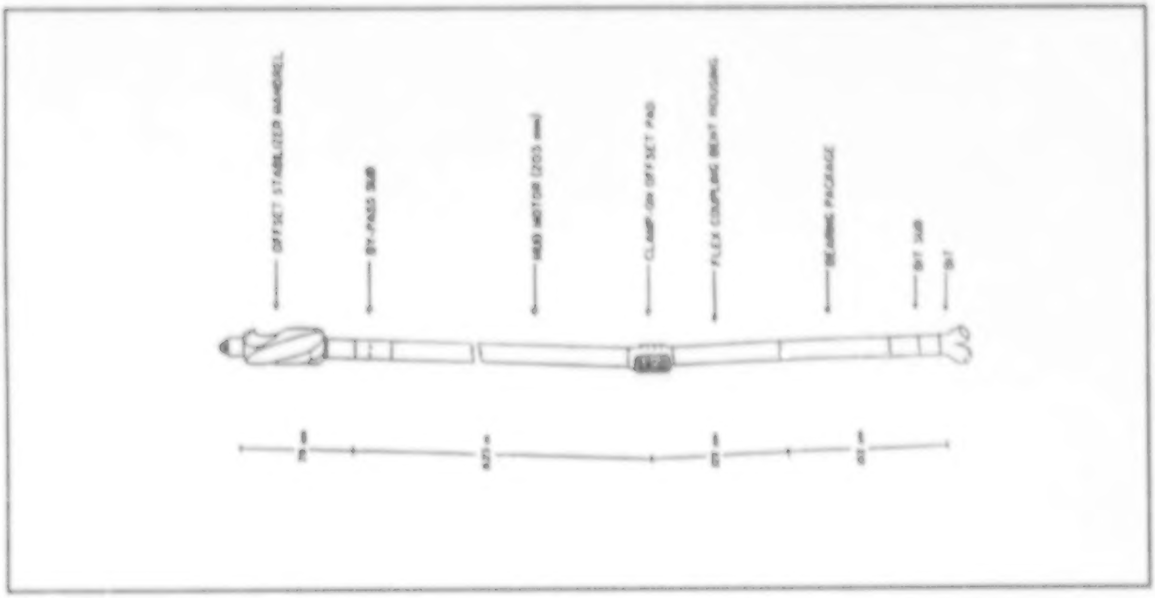

OFFSET STABILIZED MANDREL
BY-PASS SUB
MUD MOTOR (203 mm)
CLAMP-ON OFFSET PAD
FLEX COUPLING BENT HOUSING
BEARING PACKAGE
BIT SUB
BIT

Figure 11
Central Mud System and Building Layout for Pad Drilling

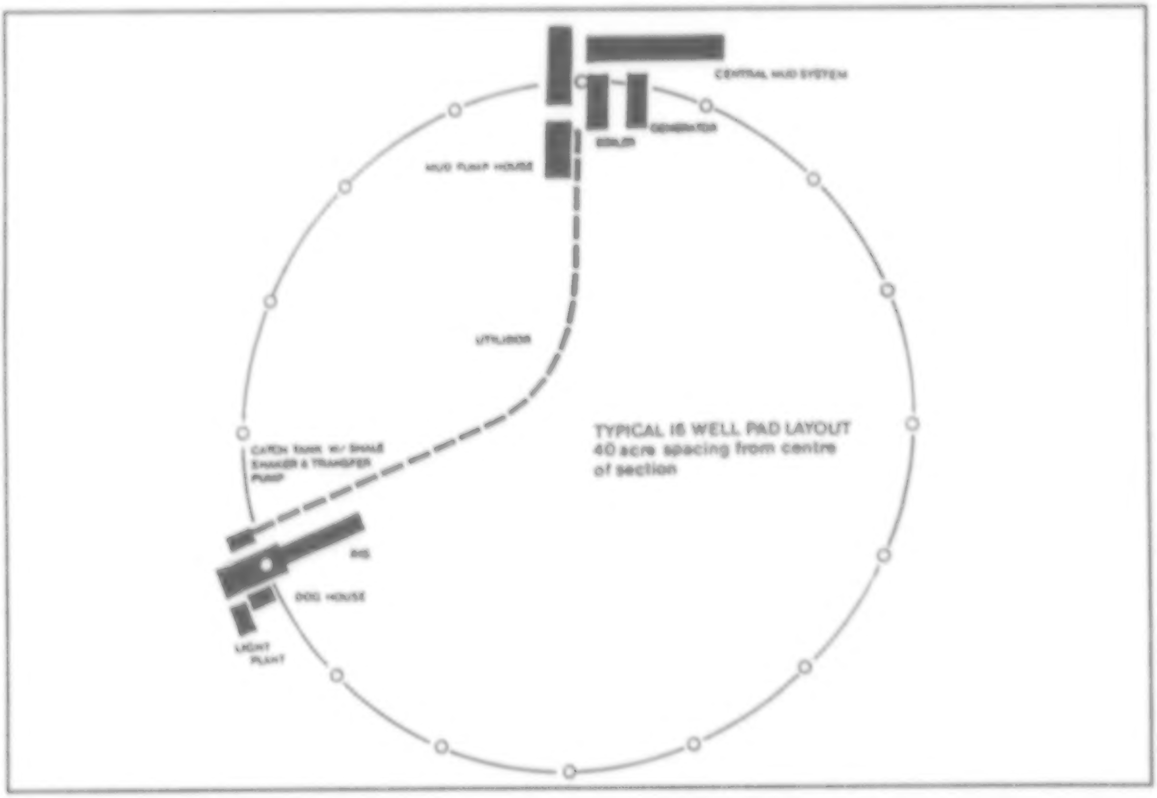

CENTRAL MUD SYSTEM
GENERATOR
BOILER
MUD PUMP HOUSE
UTILIDOR
TYPICAL 16 WELL PAD LAYOUT
40 acre spacing from centre of section
CATCH TANK W/ SHALE SHAKER & TRANSFER PUMP
RIG
DOG HOUSE
LIGHT PLANT

Figure 12
Directional Completion Plot for: Grand Prix PCB Bantry 14-34-18-14 W4M

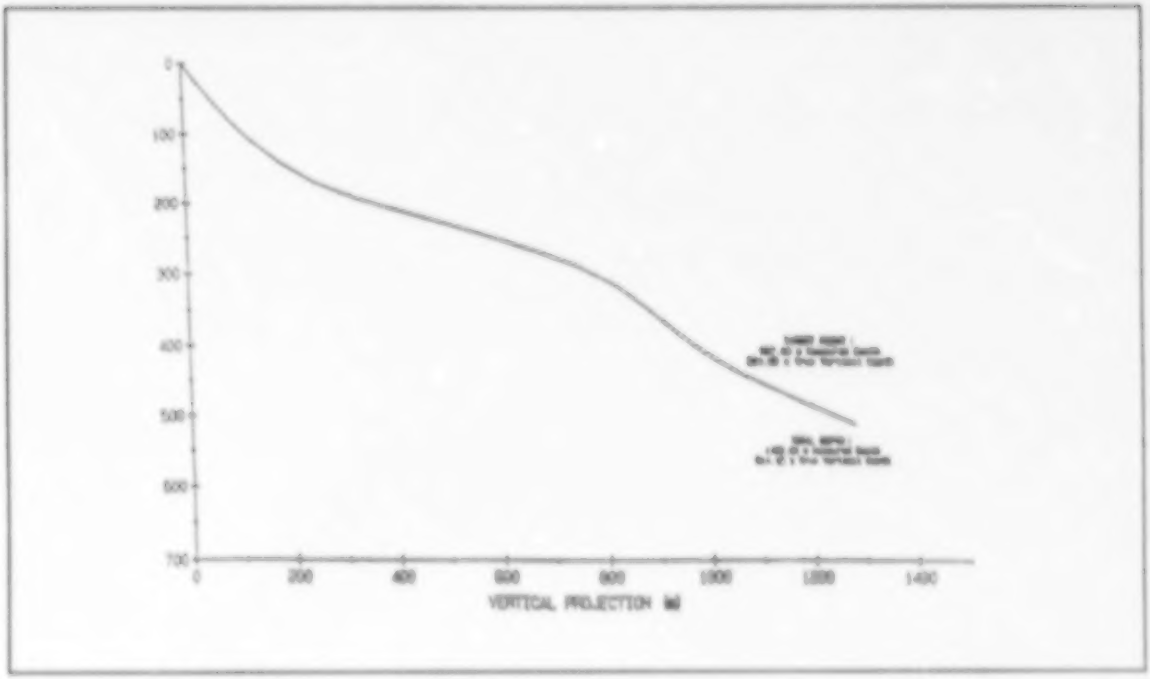


Figure 13
Directional Completion Plot for: Grand Prix PCB Bantry 14-34-18-14 W4M

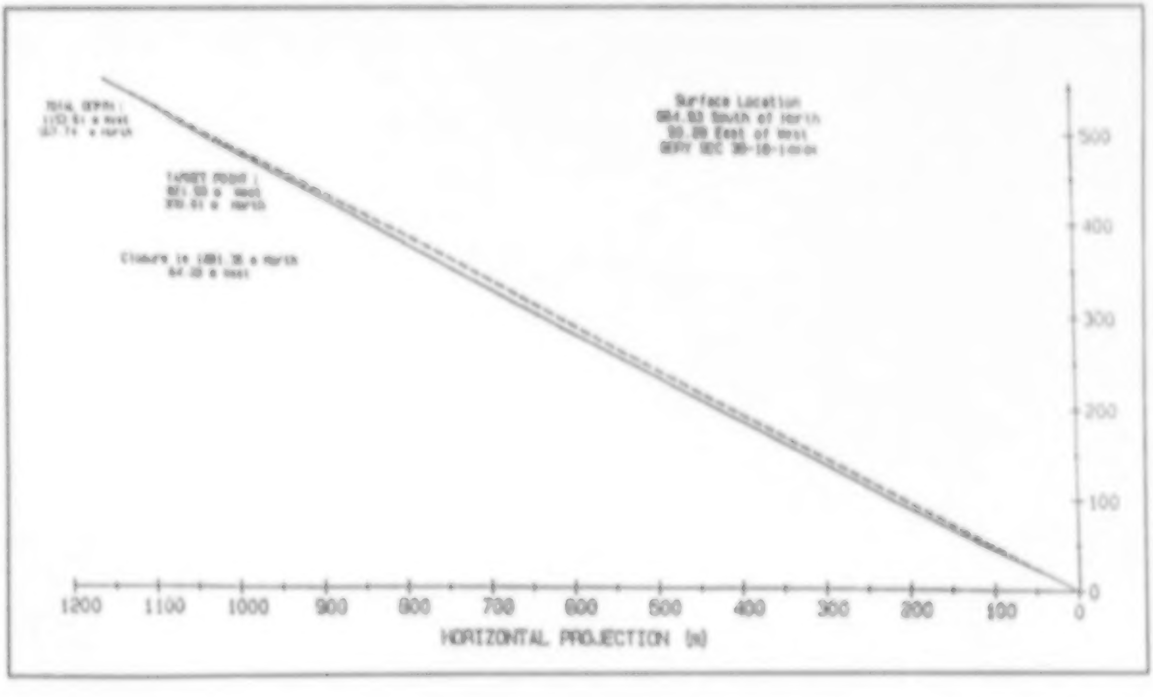
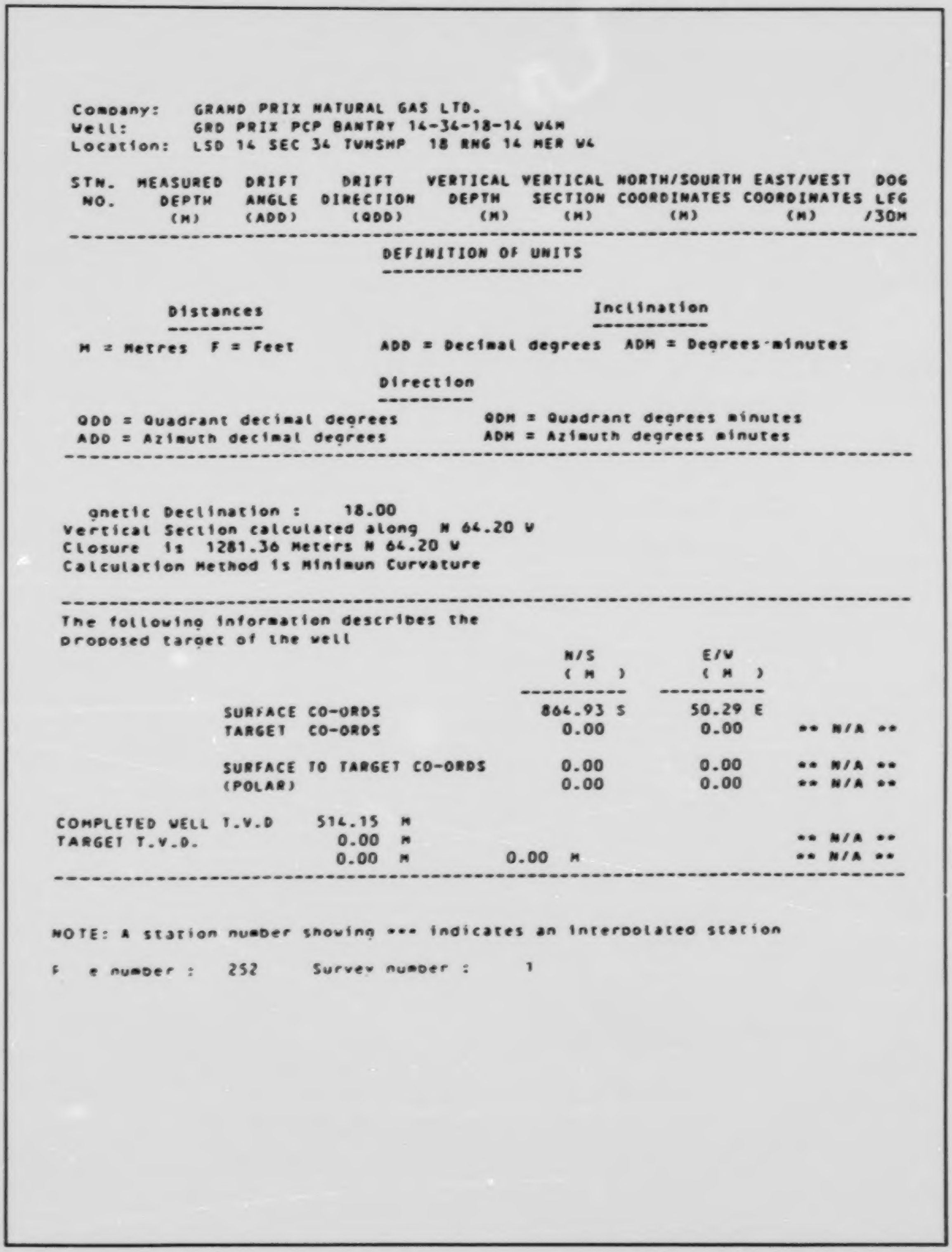


Figure 14
Completed Directional Surveys

Company: GRAND PRIX NATURAL GAS LTD.
Well: GRD PRIX PCP BANTRY 14-34-18-14 W4M
Location: LSD 14 SEC 34 TWNSHP 18 RNG 14 MER W4

STN. NO.	MEASURED DEPTH (M)	DRIFT ANGLE (ADD)	DRIFT DIRECTION (ODD)	VERTICAL DEPTH (M)	VERTICAL SECTION (M)	NORTH/SOURTH COORDINATES (M)	EAST/WEST COORDINATES (M)	DOG LEG /30M
TIEIN	0.00	45.00	N 64.00 W	0.00	0.00	0.00 N	0.00 E	0.00
1	26.00	44.25	N 64.00 W	18.50	18.26	8.01 N	16.42 W	0.87
2	54.00	47.25	N 67.00 W	38.04	38.30	16.31 N	34.66 W	3.95
3	91.00	49.75	N 67.00 W	62.56	65.97	27.13 N	60.16 W	2.03
4	128.00	52.50	N 66.00 W	85.78	94.75	38.62 N	86.57 W	2.32
5	165.00	56.00	N 66.00 W	107.39	124.74	50.83 N	113.99 W	2.84
6	228.00	62.00	N 66.00 W	139.82	178.65	72.76 N	163.25 W	2.86
7	303.00	71.25	N 64.00 W	169.55	247.25	101.79 N	225.42 W	3.77
8	379.00	77.00	N 64.00 W	190.33	320.26	133.80 N	291.04 W	2.27
9	454.00	78.00	N 65.00 W	206.56	393.47	165.32 N	357.12 W	0.56
10	529.00	78.25	N 64.00 W	222.00	465.86	196.91 N	423.36 W	0.40
11	604.00	77.50	N 64.00 W	237.75	540.19	229.06 N	489.27 W	0.30
12	678.00	76.75	N 65.00 W	254.24	612.32	260.11 N	554.38 W	0.50
13	744.00	77.00	N 65.00 W	269.23	676.59	287.28 N	612.63 W	0.11
14	816.00	73.25	N 65.00 W	287.71	746.14	316.67 N	675.66 W	1.56
15	891.00	66.25	N 64.00 W	313.65	816.37	346.89 N	739.06 W	2.82
***	902.00	65.13	N 63.87 W	318.18	826.39	351.30 N	748.06 W	3.16
16	965.00	58.50	N 63.00 W	347.94	881.77	376.06 N	797.61 W	3.16
***	974.00	58.66	N 62.84 W	352.63	889.45	379.56 N	804.44 W	0.69
***	975.50	58.68	N 62.81 W	353.41	890.73	380.14 N	805.58 W	0.69
***	987.00	58.88	N 62.61 W	359.37	900.56	384.65 N	814.32 W	0.69
***	997.00	59.06	N 62.44 W	364.52	909.13	388.61 N	821.93 W	0.69
***	999.00	59.09	N 62.40 W	365.55	910.84	389.40 N	823.45 W	0.69
***	1006.00	59.22	N 62.28 W	369.14	916.85	392.19 N	828.77 W	0.69
***	1007.50	59.24	N 62.25 W	369.91	918.14	392.79 N	829.91 W	0.69
17	1022.00	59.50	N 62.00 W	377.30	930.61	398.62 N	840.94 W	0.69
***	1036.00	60.29	N 62.19 W	384.32	942.71	404.29 N	851.64 W	1.79
***	1037.00	60.35	N 62.20 W	384.81	943.58	404.70 N	852.41 W	1.79
***	1060.00	61.70	N 62.50 W	395.96	963.69	414.03 N	870.23 W	1.79
***	1072.00	62.42	N 62.66 W	401.58	974.28	418.91 N	879.64 W	1.79
18	1099.00	64.00	N 63.00 W	413.73	998.35	429.91 N	901.06 W	1.79
***	1117.00	65.06	N 63.25 W	421.47	1014.60	437.25 N	915.56 W	1.86
19	1173.00	68.50	N 64.00 W	443.53	1066.02	460.09 N	961.63 W	1.86
[illegible]	1296.00	75.00	N 63.00 W	482.03	1182.64	512.15 N	1065.99 W	1.60
	1400.00	69.00	N 62.00 W	514.15	1281.36	557.74 N	1153.61 W	1.75

Figure 15
Completed Directional Surveys



```
Company:    GRAND PRIX NATURAL GAS LTD.
Well:       GRD PRIX PCP BANTRY 14-34-18-14 W4M
Location:   LSD 14 SEC 34 TWNSHP  18 RNG 14 MER W4

STN.  MEASURED  DRIFT    DRIFT    VERTICAL VERTICAL NORTH/SOURTH EAST/WEST  DOG
 NO.    DEPTH   ANGLE  DIRECTION   DEPTH    SECTION COORDINATES COORDINATES LEG
         (M)    (ADD)    (QDD)      (M)      (M)        (M)         (M)    /30M
------------------------------------------------------------------------------
                           DEFINITION OF UNITS
                           -------------------

        Distances                                 Inclination
        ---------                                 -----------
 M = Metres  F = Feet         ADD = Decimal degrees  ADM = Degrees-minutes

                           Direction
                           ---------
 QDD = Quadrant decimal degrees        QDM = Quadrant degrees minutes
 ADD = Azimuth decimal degrees         ADM = Azimuth degrees minutes
------------------------------------------------------------------------------


  gnetic Declination :     18.00
Vertical Section calculated along  N 64.20 W
Closure  is  1281.36 Meters N 64.20 W
Calculation Method is Minimun Curvature

------------------------------------------------------------------------------
The following information describes the
proposed target of the well
                                               N/S          E/W
                                              ( M  )       ( M  )
                                            ----------   ----------
               SURFACE CO-ORDS                864.93 S     50.29 E
               TARGET  CO-ORDS                  0.00         0.00      ** N/A **

               SURFACE TO TARGET CO-ORDS        0.00         0.00      ** N/A **
               (POLAR)                          0.00         0.00      ** N/A **

COMPLETED WELL T.V.D    514.15  M
TARGET T.V.D.             0.00  M                                      ** N/A **
                          0.00  M        0.00  M                       ** N/A **
------------------------------------------------------------------------------


NOTE: A station number showing *** indicates an interpolated station

F   e number :   252      Survey number :      1
```

12

SLANT WELLS IN THE LINDBERGH HEAVY OIL DEVELOPMENT

B.W. Stasiuk

D.M. Marjerrison

R.M. Scarborough

Dome Petroleum Limited

ABSTRACT

Heavy oil thermal projects require close well spacing to obtain high recoveries. Development of various EOR schemes can be accomplished using three drilling and completion techniques; straight, directional or slant wells. Straight hole drilling has been the standard in the past for many of the recovery schemes in Western Canada. Recently, directional and slant well drilling from pads have become widely accepted to minimize surface land disturbance.

Dome Petroleum Limited has drilled and operated each well type in the Lindbergh area. To maximize the viability of a thermal project, design must address drilling, flowline, operating and land costs. Based on results obtained to date, which are presented in this paper, slant wells were chosen as the development scheme in the Lindbergh area.

INTRODUCTION

Dome Petroleum Limited has constructed and operated five different Enhanced Oil Recovery projects in the heavy oil deposits surrounding Lloydminster, Alberta. These projects are outlined in Table 1, along with the recovery scheme and well spacing in use. The drilling method, slant, directional or straight, used for each project is primarily dependent on the well spacing required and whether agricultural use of the land is necessary during the life of the project. This is important in the Lindbergh area as agriculture is the major industry.

The projects will use air, oxygen or steam displacement as the final recovery method after initial formation heating by cyclic steaming. The majority of the projects have 10 acre spacing, except for seventeen wells on Section 18-55-5-W4M spaced at 3 acres to investigate oxygen fireflooding.

The typical section developments associated with each drilling method, along with well angles and flowline lengths are shown in Figures 1 to 3. The straight well development consists of five satellites which handle the distribution of gas, oil & water and steam for approximately 13 wells each. A group steam/production line collects the production from the 13 wells and transports the product to the main central facility.(Figure 1)

The directional well development consists of 64 wells drilled from four full pads and four half pads. Well angles range from 0° to 51.2° in the production zone with a build angle of 3°/30 metres. Twenty-four wells have bottom hole angles of 51°, twenty-eight wells have bottom hole angles of 38° and the remainder are drilled vertically. (Figure 2)

The slant well development consists of four pads of sixteen wells each located in the center of each quarter section. Well spud angles are 33° for 16 wells, 25° for 32 wells and 11° for 16 wells. (Figure 3)

Each development has a bitumen and produced water treatment facility along with a steam generation plant located in the centre of the section. The pads include manifold buildings, oil and water test equipment and vent gas control equipment. Roads and pipelines connect the wells, pads and central facilities.

Both capital and operating expenses are compared for each drilling scheme to determine the optimum. Usually the one which maximizes the present value (PV) of the project is chosen unless there are other considerations, such as land use, that apply.

CAPITAL COSTS

The capital costs for each of the various types of developments were obtained from existing schemes or from engineering estimates. The major items which contribute to the capital costs for each well type are:

1. Surface Facilities

2. Surface Land Use
3. Drilling & Completion Costs
4. Intangibles

1. Surface Facilities

The main areas used in the analysis for surface facilities are:

(a) Pipelines	• steam, production & vent gas pipelines
(b) Pads	• manifolds • well test facilities • steam chokes & meters • pad electrical facilities
(c) Earthwork	• pad earthwork & grading • acess roads
(d) Electrical	• electrical cable • transformer facilities

Table 2 breaks down the capital surface facility costs for straight, slant and direction holes. Total facility costs for straight wells was \$9.04 million, \$7.70 million for directional wells and \$7.20 million for slant wells.

Pipelines for straight wells cost \$4.6 million because of the longer lines needed to connect each well. With pad development, lines need only be connected to the main pad and not to each well. Earthwork is also more extensive for straight well development.

2. Surface Land Usage

Table 3 breaks down the surface land usage for slant, directional or straight wells. Total land use is highest for straight wells requiring 75.5 acres for roads and wellsites. Slant wells and directional wells are similar, requiring 42.4 and 53.9 acres respectively. Battery site usage was not taken into consideration as this is the same for all schemes.

Pad sizes for directional wells were smaller (460′ x 460′) while slant wells required pad sizes of 560′ x 560′. Single well sites were approximately 2 acres in size or 300′ x 300′.

Straight wells need over 120 acres more land than slant or directional wells. This represents an annual incremental land leasing cost of approximately \$100,000/yr for straight wells.

3. Drilling & Completion Costs

❑ *a) Drilling Experience & Costs*

(i) PRIMROSE

Dome's first slant wells were drilled in Primrose (Section 5-67-4-W4M) and the 10 wells were spudded at angles ranging from 22.5° to 35°. The rig used to drill these wells had only drilled three wells previously and encountered many equipment and start-up problems. Costs to drill the wells averaged \$302/m (\$92/ft).

(ii) LINDBERGH

Dome began its slant hole drilling operations in the NE Quarter of Section 10-56-6-W4M in July 1985. A total of 15 wells were drilled at an average rig release to rig release time of 3.47 days. The use of 20 metres of conductor pipe (preset with a rat hole rig at various angles) instead of 180 metres of surface pipe reduced the drilling time significantly. The average well cost was \$255/m (\$78/ft).

During the first quarter of 1986, the NW and SW pads of Section 10-56-6-W4M were drilled. Separate drilling rigs were contracted to drill out each pad. Drill rig #1 was one of the original slant drill rigs and was noticeably slower than drill rig #2 which was newer and was built incorporating technological advances. Average time to round trip 700 m was eight hours for rig #1 compared with four hours for rig #2. Similarly, connection times were approximately eight minutes for rig #1 versus three minutes for rig #2.

A breakdown of the drilling costs is shown in Table 4 for the straight, slant and directional wells.

From the analysis of the three slant pads drilled in Lindbergh it was possible to draw several conclusions:

- *(a) Down hole directional tools help reduce drilling time and produce a smoother well bore.*
- *(b) Use of 20 m of conductor pipe pre-set by rat hole rig saves on drilling time (\$10,000/well).*
- *(c) Use of cased hole logging eliminated the use of open hole logs which again reduces drilling time. (\$10,000/well).*

Cost for the slower rig #1 averaged $243/m while the rig #2 costs were $218/m. Dome's Drilling department has set goals of $200/m and average spud to rig release times of 2 days for the next pad to be drilled in Lindbergh. Once competition exists and more slant rigs are available, the costs are expected to drop to $195/m and this is included in the cost breakdown.

Problems encountered with doglegs and cementing will be discussed in a later section.

Presently Dome is investigating the use of cross-drilling strategy in the Lindbergh area. In the present operations, wells drilled on the west half of the pad are drilled outwards or to the west half of the quarter section and similarly for the east half. With a cross drill strategy, wells spudded on the west half of the pad have a bottom hole location on the east half of the section. The land and surface facility cost would be reduced by approximately $500,000/section. This savings was not considered in the evaluation since it is in the development stage.

❑ *b) Completion Costs*

Completion costs for the slant and directional pads are similar. Table 4 outlines the costs for all three schemes. Straight wells are the least expensive due to shorter well lengths resulting in less rods and tubing and no rod centralizers or special rod boxes. Completion problems associated with servicing and rod or tubing wear are detailed in operating costs.

■ 4. Intangibles

The Lindbergh area of development is used extensively for agricultural operations. Efforts must be made to save the farmland as well as obtain the optimum operating scheme for the oil company.

A study was commissioned by Dome to investigate the impacts for farmers on central pad development versus straight well development. The main conclusions were:

a) Less land is needed for slant well development.

b) Less areas of double seeding, fertilizing and spraying (crossover) for slant pads (20% yield reduction).

c) Trampling or misses were also reduced with slant pads (40% reduction).

d) There are less obstacles and roads with slant pads which leads to a 50% reduction in farming time.

No monetary value was placed on the problems outlined in the analysis. The positive public relations established with pad development prepares the farmer and/or public for intensified use in the future.

OPERATING

Operating expenses for each type of section development are determined from operating experience to date. The major items which change the operating expense for each well type are:

1. Servicing
2. Rod and Tubing Wear
3. Heat Loss
4. Surface Equipment

■ 1. Servicing

The variables which affect the operating cost due to well related servicing are the hourly cost of the rig, the servicing frequency required and the total hours involved. Included in the next section is servicing related to jobs caused by rod and tubing wear. Table 5 contains the servicing frequency, in jobs/well/month (j/w/m), for different well spacings and types. On the 10 acre spacing there appears to be no discernable difference between the different well types, with an average servicing frequency of 0.4 j/w/m for Section 10-56-6-W4M. A notable difference does occur from 40 acre to 10 acre spacing as the servicing is tripled on the smaller well spacing. This is probably due to interference effects between wells with the smaller spacing.

Table 6 contains the average length of a service job for the straight and slant wells on Section 10. The slant wells are split into three categories, wells which are spudded straight, spudded at 25° and those spudded at 33°. On a typical section development there would be 16, 32 and 16 wells in each category respectively. Section 10 has thirteen original straight wells which were on the section before the slant well development. The average of these original wells (19.5 hrs/job) is comparable to the wells spudded straight and drilled directionally to an offset angle of 11° (18.6 hrs/job). The average of these two well types is 19 hrs/job which provides a baseline average for straight well development. Slant wells drilled at 25° have an increase in average job length to 22.6 hrs/job and the 33° wells are slightly higher at 22.9 hrs/job. The reasons for the longer job times are as follows:

- ☐ *a. Longer hole length. A 25° well has 10% more pipe in the hole than a straight well. The 33° wells have 15% more pipe which accounts for the slightly higher (.3 hrs/job) rig time required.*

- ☐ *b. Longer set-up time. The Slant wells which are producing with a hydraulic unit require more time to lay down and pick up the unit than a straight well does. This is due to having to lift the unit past vertical before it can be laid down. The time required to do this is .5 to 1 hr/job.*

- ☐ *c. Pipe handling. The pipe has to be tripped in and out of the well at an angle. This is done hydraulically on a slant service rig but is not as fast as a conventional rig servicing a straight well. This difference has been reduced as the rig crews become more efficient.*

Due to the more complicated nature of the rig required for slant well servicing, the hourly cost is higher. The difference expected in the hourly charge over the long term is expected to be 10%.

These variables are rolled together to determine the incremental operating expense for each section development. The servicing hours per job are shown in Table 6. A cost of $180/hour for conventional rigs and $200/hour for slant rigs was used in the analysis. A servicing frequency of 0.4 j/w/m is used to generate Table 8. The frequency of 0.4 j/w/m is for primary operations. If thermal operations are performed, our experience shows an increase in job frequency can be expected but the total cost will be reduced by the lower time required per job.

2. Rod and Tubing Wear

Table 5 contains the number of service jobs related to wear on Section 10 in the first year of operations. The most severe problem occurs in the 25° slant wells indicating that the well angle does not affect the problem. An analysis of the wells with the problem shows that these are the most off-target. Corrections were made on the hole angle closer to the zone on problem wells than wells with no problems. The result is less straight hole above the pump to alleviate friction in that area. Reports from the field indicate that the majority of the wear is in the bottom section of the rod string.

The wells on Section 10 do not have enough history to provide data on the operating cost due to rod/tubing wear. Tubing replaced on the directional development at Dome's Morgan project was used to estimate the problem. The tubing replaced and the service jobs as a result of failure for each hole angle is shown in Table 7. These costs are combined with the average job length in Table 6 and increased 50% to account for rod box replacement. Slant wells should reduce the problems which cause the rod and tubing wear as there are less severe hole angles. This is evidenced in Table 5 where the problems encountered on the 33° slant wells are similar to those on the straight and the 11° directional. Dome expects the slant wells to fall between the straight and directional wells in wear problems and is estimated at 50% of the difference. Table 8 contains the total incremental cost associated with each type of section development.

Various methods of alleviating the wear on the directional and slant wells have been tried. Coated boxes have been used on screw-type pumps and the roller type rod boxes have been tried on stroking units. There is no consensus yet on the effectiveness of these methods due to insufficient history.

3. Heat Loss

Dome's thermal operations require steam injection at each well 20% of the time. Heat loss from the extra surface line required for straight wells is offset by the extra wellbore of directional or slant wells. The surface line requirements of each section development is shown in Figures 1 to 3. Heat losses of 200 BTU/hr/ft for surface line and 400 BTU/hr/ft in the wellbore lead to $30,000 - 40,000/yr extra expense for the straight wells, as shown in Table 8.

4. Surface Equipment

Some problems with wear on surface equipment occurred immediately after production started on the slant wells. Larger drive units were required on slant hole wells equipped with progressive cavity pumps. The stroking wells had problems with stuffing box packing wearing out in a few days. This problem was solved by supporting the polish rod above the packing. There may be long-term wear problems associated with higher rod loads (25%) on the slant wells. Cost advantages associated with pad design, on items such as lease clean-up, road maintenance, corrosion protection, rig movement in break-up and equipment maintenance are easier to accomplish. Another advantage to pad design comes from lower flowline pressures in a group system which benefits the production rate. Straight wells on Section 18 have had flowline pressures up to 1,000 psi, which causes the shut-down of the wells for a short period. These items easily offset each other resulting in no incremental costs on any of the section developments.

Table 8 contains the incremental yearly operating cost of slant and directional wells over straight well development. The extra cost associated with pad development is close to $200,000/yr. These differences may be lessened as new technology is developed. Smoother well bores with slant well drilling will benefit the rod/tubing wear problems.

SUMMARY

Table 9 summarizes the costs associated with slant, directional and straight well development for the Lindbergh area. The total capital cost for all three developments were similar averaging $22.8 MM. The slant well development was the least expensive at $22.65 MM while the straight well development was the most expensive at $22.84 MM. Incremental operating costs are $115 K/yr more for slant and directional wells over straight. The difference in these costs is insignificant when compared to the total cost of a section development in the Lindbergh area. Land use requirements overrode other considerations and led to slant well development.

The above analysis was carried out specifically for the Lindbergh area. Different operating parameters, such as zone depth, zone thickness, well spacing and surface land use, will change the operating and capital costs. Each company needs to apply a similar analysis to determine their optimum development scheme.

CONCLUSIONS

☐ *1. Slant well surface facility costs are the least expensive but is offset by higher drilling & completion costs. Costs could be further reduced by $500K with the use of cross drill technology.*

☐ *2. The difference in present value represented by the operating cost savings with straight wells is insignificant.*

☐ *3. Intangibles, such as land usage, are a deciding factor in the determination of the type of section development used.*

TABLE 1
DOME'S HEAVY OIL PROJECT CHRONOLOGICAL SUMMARY

YEAR	PROJECT/ FIELD	RECOVERY METHOD	# WELLS	DEVELOPMENT SCHEME	SPACING (ACRE/WELL)
1980	Morgan	Combustion/ Steam	45	Directional	10
1981	Lindbergh 18-55-5-W4M	Combustion/ Steam	65	Straight	10 & 3
1982	Primrose 5-67-4-W4M	Steam	42	Directional/ Slant	2 & 6
1983	Lindbergh 24-55-6-W4M	Steam	61	Straight	10
1985	Lindbergh 10-56-6-W4M	Primary/ Steam	46	Slant	10

TABLE 2
LINDBERGH DEVELOPMENT SCHEME SURFACE FACILITY COSTS ($MM)

	SLANT	DIRECTIONAL	STRAIGHT
PIPELINES	1.500	2.150	4.650
PAD FACILITIES	4.900	4.300	2.100
LEASE/EARTHWORK	0.550	0.750	1.600
ELECTRICAL	0.250	0.500	0.700
TOTAL ($MM)	**7.200**	**7.700**	**9.050**

TABLE 3
LINDBERGH DEVELOPMENT SCHEME
LAND USAGE (acres)

	SLANT	DIRECTIONAL	STRAIGHT
ROADS	13.8	19.6	47.5
PADS/WELLSITE	28.6	34.3	128.0
TOTAL	**42.4**	**53.9**	**175.5**

TABLE 4
LINDBERGH DEVELOPMENT SCHEME
DRILLING COSTS

	SLANT	DIRECTIONAL	STRAIGHT
AVG. LENGTH (m)	663	659	600
AVG. COST ($/m)	195	190	181
TOTAL DRILLING COSTS ($MM)	8.27	8.01	6.95
COMPLETION COSTS ($MM)	7.18	7.15	6.84
TOTAL DRILL & COMPLETE	**15.45**	**15.16**	**13.79**

TABLE 5
SERVICING, FIRST YEAR OF OPERATION

Section	Spacing (Acre/Well)	Description	# of Wells	Jobs/well/Month	Tbg/Rod Problems
10-56-6	40	Straight	13	.17	1
	10	Directional, 11°	11	.61	3
	10	Slant, 25°	20	.33	15
	10	Slant, 33°	12	.30	2
18-55-6	40	Straight	6	.11	N/A
	3,10	Straight	50	.50	N/A

TABLE 6
SERVICING HOURS/JOB

Section	Description	# of Jobs	Hours/Job
10-56-6	Straight	44	19.5
	Directional, 11°	77	18.6
	Slant, 25°	107	22.6
	Slant, 33°	55	22.9
	Directional (16°) *		20
	Directional (21°) *		21

** estimated on hole length, well angle represent offset distance*

TABLE 7
TUBING REPLACEMENT, MORGAN
(SINGLE WELL, YEARLY BASIS)

Description	# of Wells	TBG Joints Replaced	Service Jobs
Straight	12	2.5	0.5
Directional (13° - 18°)	13	5.0	1.0
Directional (19° - 23°)	14	6.5	1.25

TABLE 8
INCREMENTAL EXPENSES FOR A SECTION DEVELOPMENT
($K/yr)

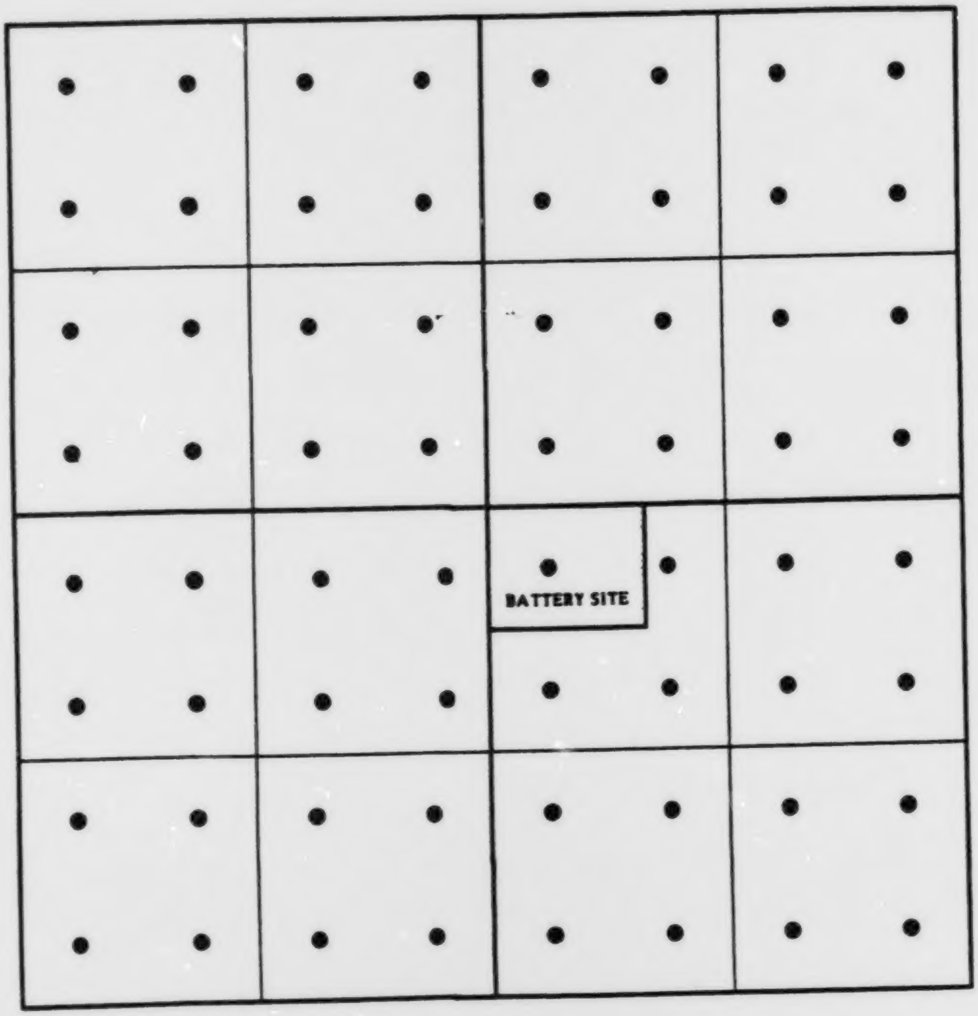
ITEM	STRAIGHT	DIRECTIONAL	SLANT
Servicing (.4 j/w/m)	0	65.7	170.5
Rod/Tubing Replacement	0	171.4	85.2
Surface Equipment	0	0.0	0.0
Heat Loss	0	(31.5)	(40.8)
TOTAL		**205.6**	**214.9**

TABLE 9
LINDBERGH DEVELOPMENT SCHEME
ECONOMIC SUMMARY

	SLANT	DIRECTIONAL	STRAIGHT
CAPITAL COSTS			
Surface Facilities ($mm)	7.20	7.70	9.05
Drill & Complete($mm)	15.45	15.16	13.79
TOTAL ($MM)	**22.65**	**22.86**	**22.84**
YEARLY COSTS			
Land ($k/yr)*	32	40	132
Incremental Operating ($k/yr)	215	205	0
TOTAL ($K/YR)	**247**	**245**	**132**

**Estimated @ $750/Acre*

Figure 1
Lindbergh Section Development - Flowlines: 19500 METERS



STRAIGHT

Figure 2
Lindbergh Section Development - Flowlines: 85500 METERS

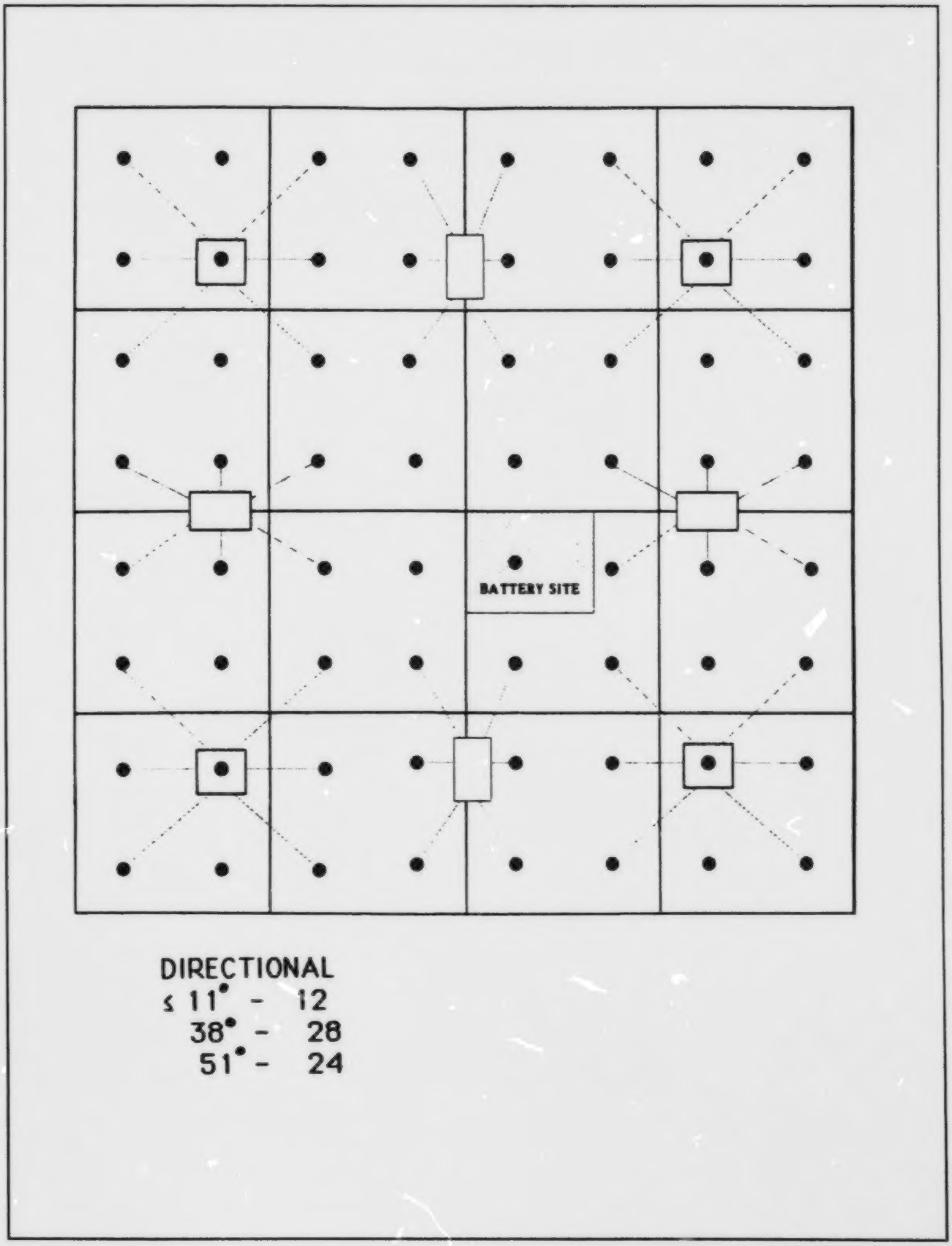
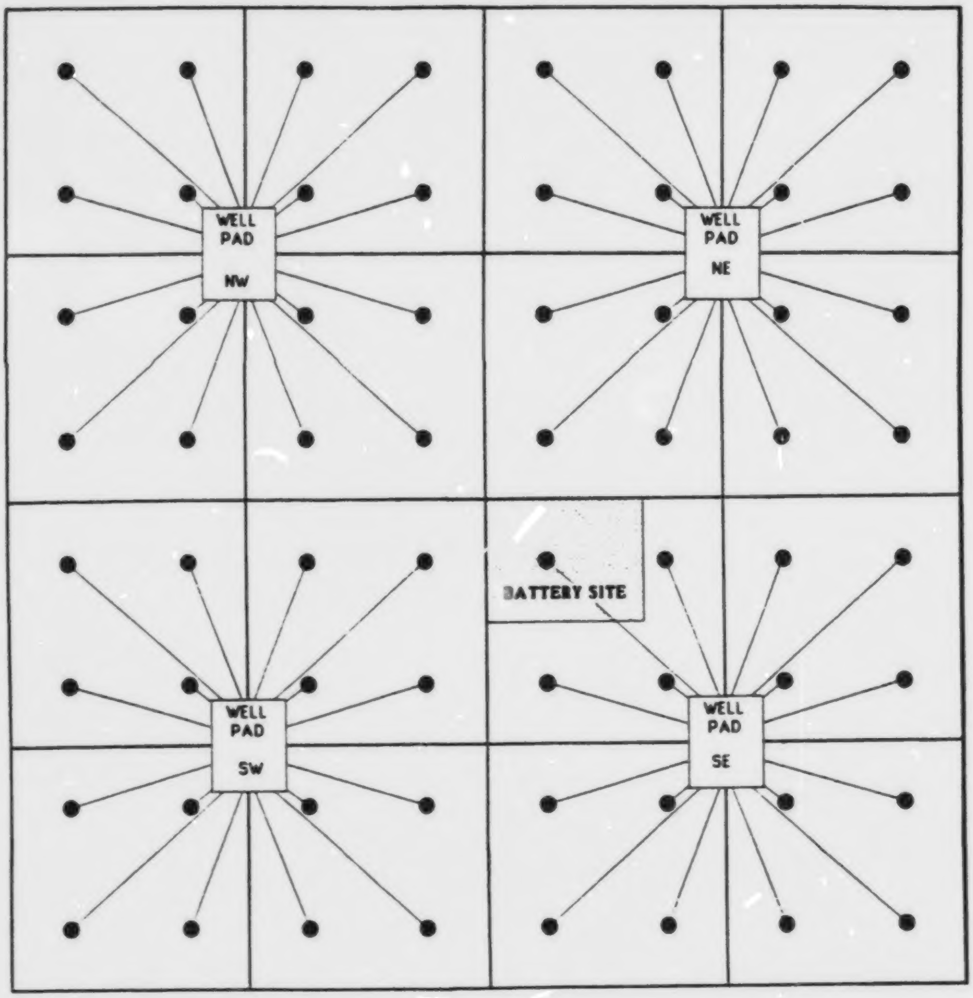

BATTERY SITE
DIRECTIONAL
≤ 11° - 12
38° - 28
51° - 24

Figure 3
Lindbergh Section Development - Flowlines: 8200 METERS


WELL PAD NW
WELL PAD NE
WELL PAD SW
WELL PAD SE
BATTERY SITE

SLANT
≤ 11° - 16
25° - 32
32° - 16

Figure 4
Dome's Slant Well Drilling Experience

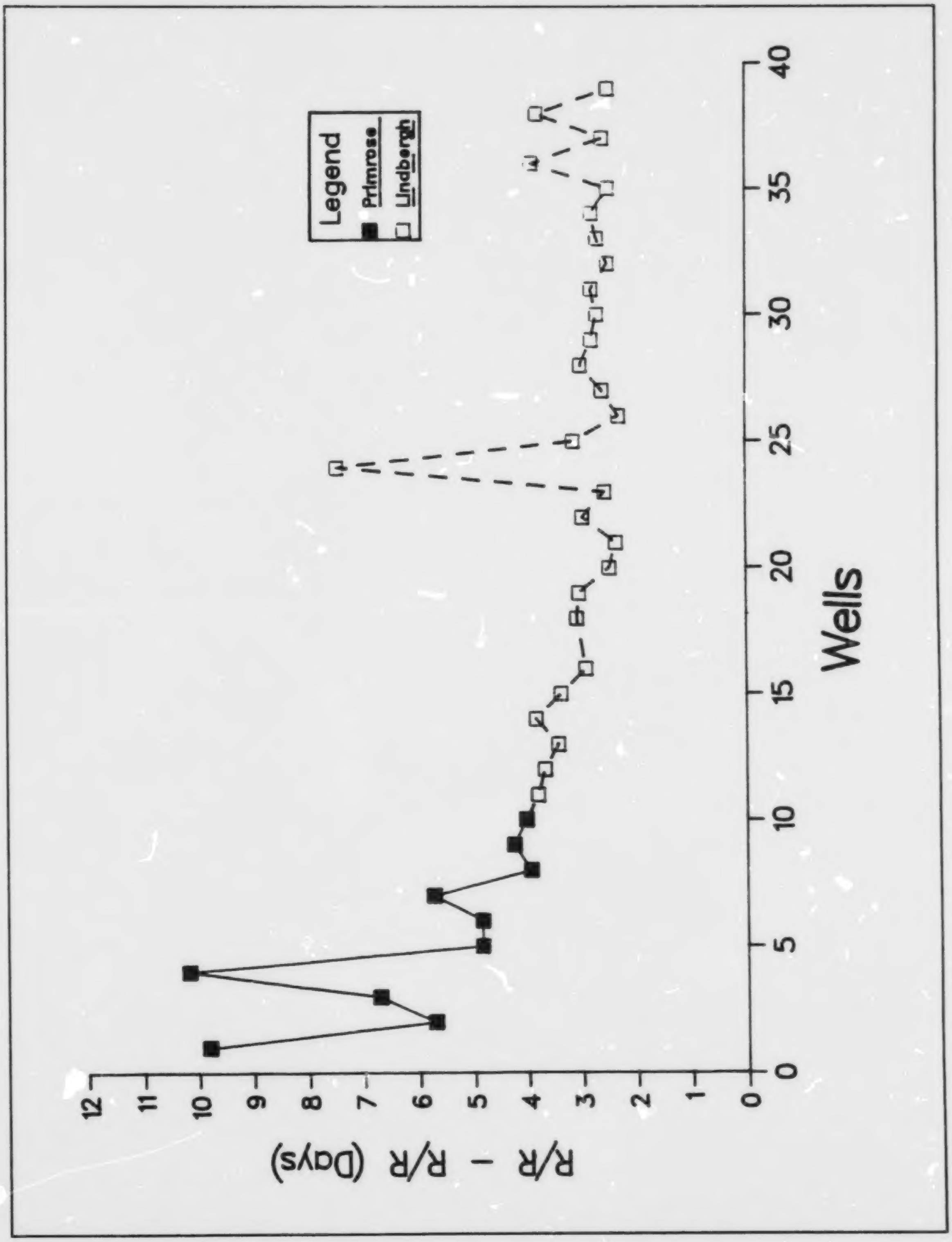


Figure 5
Lindbergh Commercial Project - Lindbergh Sector Location

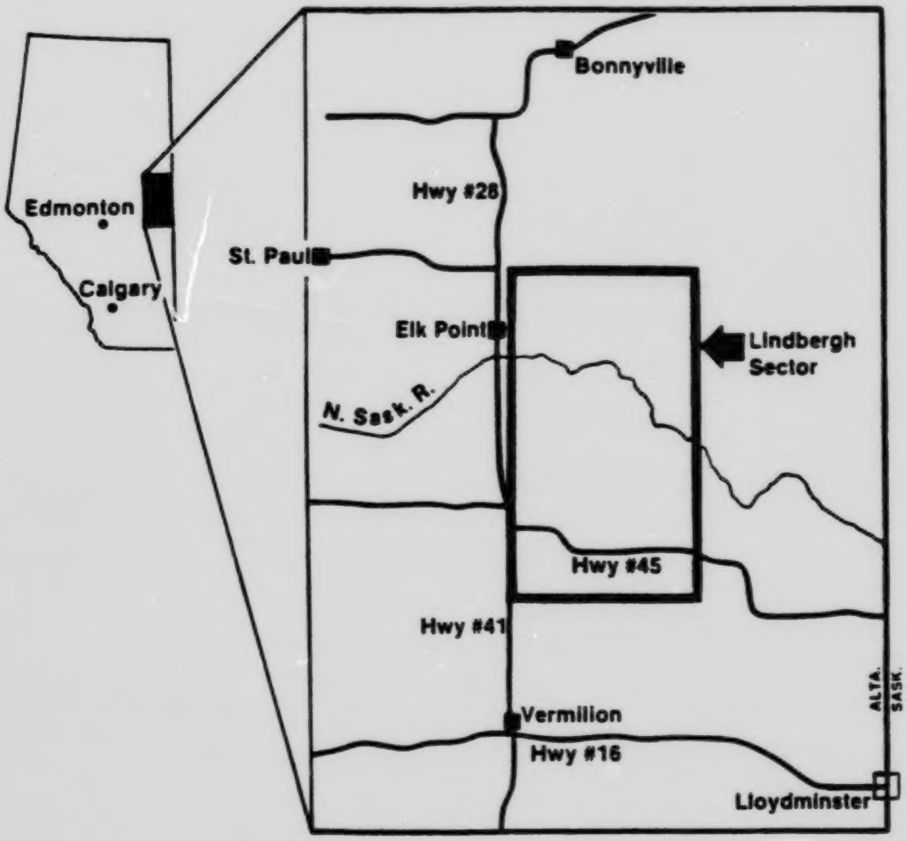

Bonnyville
Hwy #28
Edmonton
St. Paul
Calgary
Elk Point
Lindbergh Sector
N. Sask. R.
Hwy #45
Hwy #41
ALTA.
SASK.
Vermilion
Hwy #16
Lloydminster

Figure 6
Lindgergh Area Map

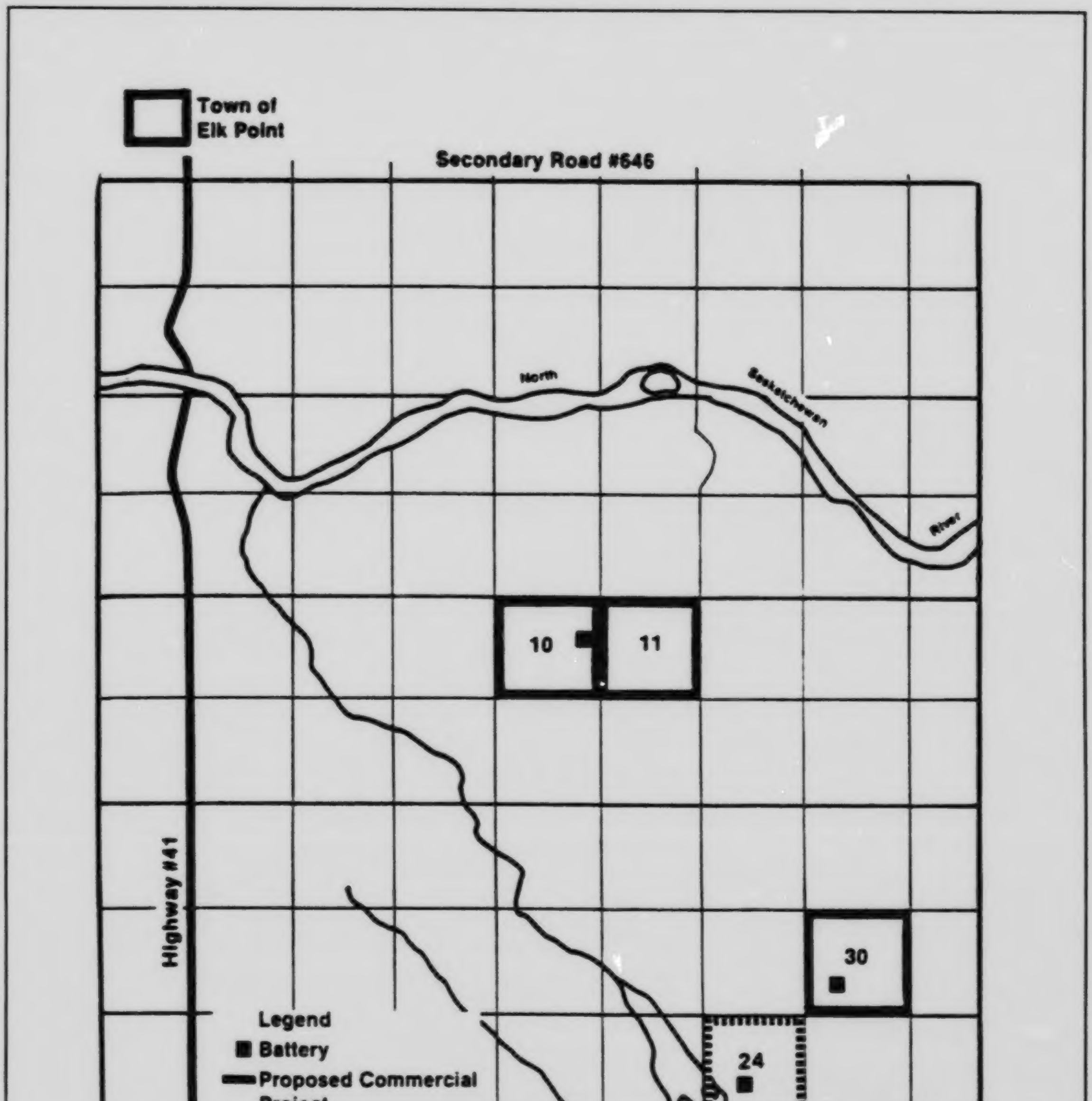
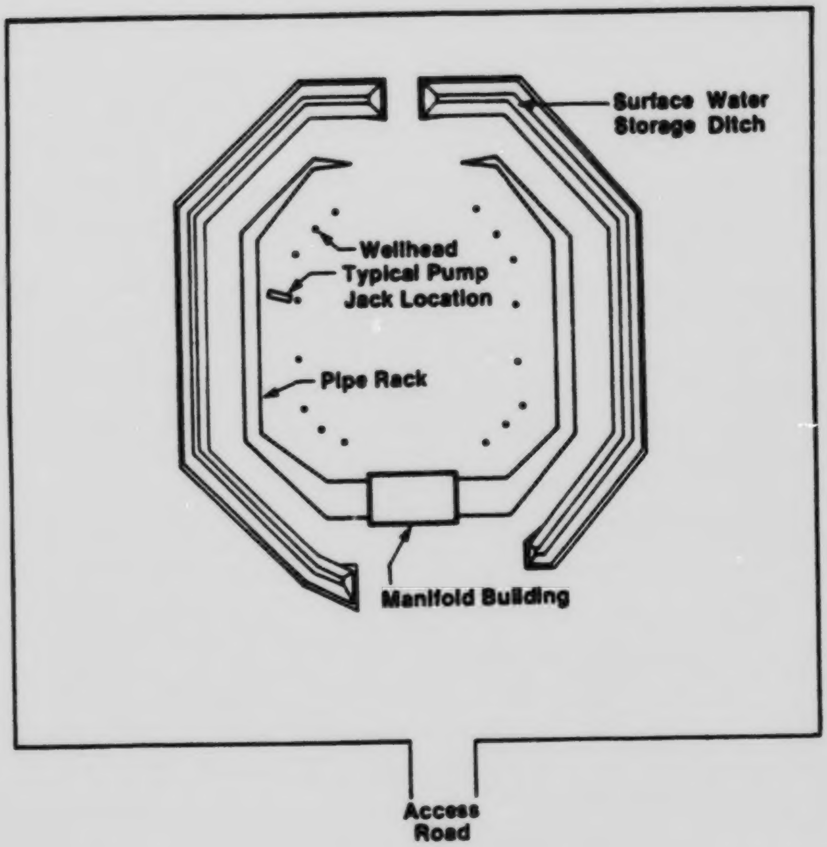

Town of Elk Point
Secondary Road #646
North
Saskatchewan
River
10
11
30
24
14
18
12
Highway #41
Legend
■ Battery
Proposed Commercial Project
Existing Experimental Developments
Secondary Road#640

Figure 7
Lindbergh Commercial Project - Well and Production Pad Layout


Surface Water Storage Ditch
Wellhead
Typical Pump Jack Location
Pipe Rack
Manifold Building
Access Road

13

TECHNICAL STUDY ON THE PUMPING TECHNIQUES FOR GAOSHENG HEAVY OIL FIELD

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Liu Shiying

Zhang Tongyi
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INTRODUCTION

Gaosheng heavy oil field is located on the northern flank of Xixiepuo in West Depression of the Liaohe basin. The reservoir is thick and lithologically a sandstone formation with a massive conglomerate where gas cap, edge water and bottom water exist. Specific gravity of produced heavy crude ranges from 0.94 to 0.96, and resin and asphaltent content from 40 to 50 %. Viscosity at 50°C is in the range of 3,000 to 4,000 cp. The produced oil is of sulfur bearing naphthenic intermediate crude.

Most wells in the field were flowing only for a short period or no flowing at all due to great depth, high viscosity and low mobility. Production can be realized only with artificial lift for improving performance of individual wells. The technical challenges that were encountered at the early stage of the field's development and production were numerous; among them were high friction caused by viscous crude, sucker rod's lagging behind, poor pumping efficiency due to low mobility of oil in wellbores, and the difficulties for oil transmission on the surface. In recent years, effort was made by Gaosheng engineering staff to test various techniques for tackling the above technical difficulties. These techniques that had been tested included heating coils in casing tubing annulus to facilitate oil flow; mixing relatively hot water from the bottom aquifer with heavy crude for reducing viscosity; and blending with surfactant solutions or diluent for improving pump performance and fluid flow in wellbores. The efforts appear to pay off as the oilfield has become one of the major heavy oil producing areas in China today.

PUMPING TECHNIQUES DURING EARLY STAGE OF PRODUCTION

Bottom water was among the artificial lift techniques used to facilitate heavy oil production at the early stage of the field's development when formation pressure was high. Wells were perforated several meters below the bottom water zone to allow relatively hot bottom water which contained small amount of solution gas to flow into wellbores through choke and mix with heavy crude. The technique reduced not only fluid viscosity but also friction both for sucker rods and pumps. Some wells were able to produce and provide good economic returns as a result of applying the technique.

One important factor determining the success or failure of the bottom water technique is to control bottom water/heavy oil ratio. When crude oil viscosity is within 3,000 cp, the amount of bottom water approximately 40 to 70 % of the total blend is required to lift fluids at 1,100 meters deep to surface fluid gathering stations. Production practice in the field shows that artificial lift with bottom water is more economical than with surfactant solution. The technique is, however, not without difficulties. One major problem is to control the flow of bottom water into wellbores as mentioned earlier. Experience with this technique shows that insufficient bottom water would cause sucker rod to "lag behind" while excess water would cause serious sand problem. Since the bottom water zone can be sealed off from wellbores quite readily with a cement plug, the technique is worth trying wherever bottom water is available even if there is a risk of running into water control problems.

The technique of using a large tubing of 4 inches in diameter inside a 7 inch casing, or sometime a 3 inch tubing in a 5 1/2 inch casing was tried with some success. Another artificial lift technique used in the past involved a surfactant solution for reducing oil viscosity. The technique was first tried at Shengli oil field and subsequently on 30 to 40% of the production wells at Gaosheng. A heavy oil emulsifier about 0.03 % in concentration was used to form a surfactant solution which was then pumped into wellbore annulus, as shown in Figure 2. The technique improved the operations of sucker rod pumps and surface fluid transmission pump, and increased average production to 7-11 tons/day/well at Gaosheng oil field. The amount of surfactant required varied between 35% and 65% of the blended volume depending on field conditions and fluid properties. One major difficulty of the technique was that, due to uneven mixing of surfactant solution with heavy oil, plug flow occurred in wellbores and surface pipelines, and impeded movement of the sucker rod. The problem was often serious enough to cause failures of sucker rods and surface gathering equipment. In addition, the reservoir was contaminated with the surfactant which affected the recovery process and resulted in severe economic consequences. The technique was eventually abandoned and replaced with diluent blending process. It should be pointed out that the surfactant blending process is still being studied and improved upon in China. In recent years, new emulsifiers have been introduced. The technique can be a viable alternative under the conditions that the heavy oil produced have to be sold locally and cannot be upgraded to produce light oil for blending; that the surfactant can be recovered and reused; and that light oil is not economically available.

PRODUCTION TECHNIQUES AT GAOSHENG

Several heavy oil pumping techniques have been developed by Gaosheng engineering staff over the years. One technique involves using N80 7 inch casing prior to well completion for sand control and for ensuring adequate supply of fluid flow from reservoir to wellbores with little or no contamination of the reservoir. To improve wellbore fluid flow and production performance, a combination of different techniques such as using large pumping equipment, long stroke pump, large tubing, strong sucker rod or setting pumping deeper was applied for producing heavy oil. Further discussions of these pumping techniques follow.

Large pumping equipment is energy efficient installation with load capacity of more than 12 tons, stroke length of 5 to 6 meters and 3 to 5 strokes per minute. Major pumps used at Gaosheng are Model 16 pumps, Model 12 chain driven pump and Model 14 air balanced pumps. Much progress has been made in developing the technology that it is possible these days to install larger pumps on deeper wells and at the same time maintain pump efficiency.

The pumping technique requires a large tubing of 4 inches in diameter inside a 7 inch casing, or a 3 inch tubing in a 5 1/2 inch casing. Sucker rods made of stronger material such as the D grade rods rather than the conventional C grade rod are used in order that the Models 12 to 14 pumps can be set at deep wells, usually about 1,400 to 1,500 meters deep. The artificial lift technique also employs an appropriate amount of diesel oil of 1.38 cp or light oil of 1.1 cp which is blended with heavy oil in wellbores to reduce oil viscosity and fluid friction, increase pump fill factor and enhance oil water separation in the central plant. About 60% of all the pumping wells at Gaosheng field employ the above pumping techniques. Average production of these wells is approximately 18.8 tons/day/well as compared to 7 to 8 tons/day/well from the remaining wells. Currently this technique is used extensively at Gaosheng; it is applicable to heavy oil production with cyclic steam stimulation as well as gas drive processes. Experience shows that production can double from the wells using the same technique and produced with cyclic steam stimulation process.

THEORETICAL INVESTIGATION OF THE PUMPING TECHNIQUE

The prime feature of the pumping technique is its ability to significantly reduce friction loss in pumping heavy oil which can be expressed by the following empirical equation,

$$P_s = K\,(L + Lb)\,n\,S\,Cp$$

$$K = 1.56 \times 10^{-7} / (M - 1.2743)$$

$$M = D_{tubing} / D_{rod}$$

where

L : Length of sucker rod

Lb : Collar Length

n : stroke per minute

S : stroke length and

Cp : crude viscosity, centipoise

The above equation shows that friction is affected by diameter ratio of tubing to sucker rod, collar number and its equivalent length, stroker length, strokes per minute and crude viscosity. Friction is significantly reduced with a larger tubing. For example, with a 1 7/8 inch composite sucker rod at a pump setting depth of 1,400 meters, friction is calculated from the above equation to be 1.15 tons for a tubing size of 4 inches. Under the same conditions, except with a 3 inch and a 2 1/2 inch tubings, frictions increase 28.1%

and 52% respectively. Friction is also reduced with less strokes per minute, or with diluent blending. Field experiments showed that for every 1,000 cp increase in fluid viscosity, friction would increase by 51.7%. We also observed that by blending 20 % of light oil of 11 cp viscosity, viscosity dropped by 61.4 %. Diluent blending is an effective way for reducing viscosity and friction loss.

The amount of diluent required in the blending process differs with different properties of heavy oil and field conditions. Typically, when crude viscosity is under 2,000 cp, there is no need to inject diluent downhole; blending is required only at the surface to keep back pressure from being too high. With crude viscosity between 2,000 and 4,000 cp, the amount of diluent required for downhole injection generally varies between 11.8 and 20% of the blend volume depending on well production. For the wells that produce 15 tons/day or higher, the amount of diluent at the lower limit of the range is generally sufficient to assist fluid flow in wellbores while the amount at the upper limit is required for wells producing between 7 and 15 tons/day. When well production is low, about 5 to 7 tons/day, diluent in the range of 20 to 25% of blend volume is usually required. The diluent volume in the blend is also affected by quality of the diluent. For example, the amount of light diesel oil required is 7 to 11.8% less than light crude. Also, oil dehydration process appears to function better with light diesel oil. In applying diluent blending at the field, caution must be taken to avoid using light crude with high wax content.

The effects of collar number and its equivalent length on friction loss is significant and should not be overlooked. The longer the sucker rod is , the greater the number of collar and its equivalent length will be required, and the higher the friction loss will become. It is felt that by employing longer sucker rods per section, the number of collar required would be reduced for the benefit of decreasing friction loss. In that regard, the authors feel that consideration should be given to manufacture sucker rods at a maximum length that is technically feasible.

Pumping efficiency and fill factor of the new production technique are significantly improved according to the laboratory tests with a scaled physical model. Results of the tests show that fill factor of the pump decreased with increasing oil viscosity; it maintained at 100 % when oil viscosity was below 200 cp, but dropped below 90% as viscosity increased to 500 cp. It is therefore essential that diluent blending be employed to effectively reduce viscosity by 1 to 2 order of magnitude in order to increase pump fill factor and well productivity.

In deep a well, stroke length of a pump plunger is usually smaller than travel of a polished sucker rod, which effectively reduces pump efficiency. To overcome the loss of pump stroke length and pump efficiency, large tubing and strong sucker rods are usually employed with the technique. Using pump with longer stroke length is also beneficial as it practically reduces the rate of stroke loss as indicated in the following table which compares performances of two pumps of different sizes and stroke lengths operated at 1,300 meters below surface over 57 hours.

PERFORMANCE OF A LARGE AND A SMALL PUMPS

	Small Pump Short Stroke	Large Pump Long Stroke
Stroke Length, Meter	2.4	5.0
Strokes/Minute	6	4
Stroke Loss, Meter	1.2	1.2
Stroke Loss,Meter/Minute	7.2	4.8
Plunger's Pumping Rate, Meter/Second	0.48	0.66

It is obvious from the data shown in the table that the performance of the larger pump with longer stroke is superior to the smaller pump in term of plunger pumping rate and effective stroke length of the pump.

Under the conditions that pump size is compatible with well production capacity, pumps should be submerged at an optimum depth of about 300 meters or more, and in no way less than 150 meters according to production statistics from Gaosheng operations. Pump fill factor would be severely affected by gas effect if pumps are set less than 150 meters below the surface. It is felt that one way to reduce pump submergence is to enlarge the intake valve of the pump so as to reduce hydraulic friction at the pump. However, with the decline in formation pressure, the increase in the amount of solution gas and gas from the gas cap would aggravate pump efficiency. It is rather urgent that field tests be conducted to investigate whether or not pumps set at 1,600 meter depth are less affected by gas.

FUTURE IMPROVEMENT ON THE PUMPING TECHNIQUE

There are rooms for improvement on the production technique being used currently at Gaosheng oilfield. First of all, it should be pointed out that the pumping equipment is too heavy to be economical. Because of its weight, the stress load, torque and dynamic load become quite large in wells with only minor sand production or wells with intermittent flows. Equipment failures are quite frequent and severe under these production conditions. It is therefore imperative that dynamic load of the pumping equipment be reduced to improve the technique. Broken sucker rod remains a key issue on the effectiveness of the heavy oil production technique. It represents 30 to 40 % of all the production failures at Gaosheng. Major causes for the broken sucker rods are due to concentration of stress around the collars, severe bending of rod and material failures. It is essential that quality of sucker rods be continually improved.

Another issue needed to be addressed regards long stroke pumps which should be further improved so that they are less affected by siltstone and gas. Manufacturing of a series of long stroke pumps is important in order to meet demands for various well conditions.

PRODUCTION TECHNIQUE FOR HIGH GOR PERIOD

With the presence of gas cap at Gaosheng, the upper reservoir is being produced by gas drive mechanism. As reservoir pressure declines, gas coning occurres, especially at those wells that were improperly managed, and produces high gas oil ratio. For the wells producing from the middle and lower reservoir, gas oil ratio also increases due to high rate of production. As of March, 1987, average gas oil ratio over the whole field reached 300 cubic meters/ton, with some wells higher than 500 cubic meters/ton. Pumping efficiency of many of the high gas wells were below 20%. According to the forecast from a geological study, gas oil ratio from the Gaosheng production will maintain at 1,200 cubic meters/ton in 1988 and for the next three years. If the forecast is correct, production at Gaosheng will enter the most trying period for the next few years.

There are several methods for heavy oil production during high gas oil ratio period. One obvious technique is to allow little or no solution gas to pass through downhole pumps. The second technique involves pumping oil through tubing while producing solution gas and heavy oil through casing. The third technique employs a gas releasing valve for depleting solution gas through casing to fluid gathering stations. After solution gas is depleted, production then proceeds with diluent blending and pumping. The third technique is being applied on 16 % of the production wells at Gaosheng. Another 16 % of the wells are produced with similar technique but with controlled casing pressure while allowing gas to deplete from the casing. Among the producing wells which use with the third technique without casing pressure control, 20 % of them produce more oil from the casing than production tubing. As the formation pressure declines and gas oil ratio increases steadily, pressure at the fluid gathering stations also increase causing operational difficulties for oil gas separation. Whatever the problems are, it is obvious that the pumping unit should be designed to allow solution gas be diverted into casing to minimize its effect on pump performance.

Production experiences at Gaosheng indicate that requirement for controlling casing pressure is different at different producing areas. At present, casing pressure is controlled in the range of 5 to 10 atmospheric pressure in some areas in order to achieve production stability, while in most of the producing areas, casing pressure is controlled at 10 to 15 atmospheric pressure to achieve good pumping and flowing effects. For the gas coning wells producing from the top reservoir, remedial actions such as production curtailment or even well shut-in should be considered. For the wells that show high gas oil ratio and are heading into serious gas coning problem, slowing down of production may alleviate the problem and reduce the composite oil gas ratio of the whole field considerably.

Another effective method for dealing with high gas production is to set pumps as deep as possible. The technique is , however, not suitable for sand production wells as sands would aggravate the problems of pump sticking. Also, sucker rod pumps with long plungers can be effective in high gas production wells because of its small clearance between the plunger and the barrel which allows no gas confinement in the pump barrel and at the same time minimize impact protection distance.

Development of a new pumping technology is essential to the stable production of heavy oil from Gaosheng oil field, especially during the high gas production period. Recognizing the technical challenge, the Gaosheng oil field wishes to collaborate and exchange ideas with foreign experts in advancing the technology in this area.

CONCLUSION

The recent production experiences from Gaosheng operations show that, by relying on our own efforts and by full utilization of reservoir natural energy, it is feasible technically and economically to produce heavy oil having specific gravity of 0.95 and viscosity of 3,000 cp at the depth from 1,300 to 1,700 meters. The engineering staff in the Gaosheng oil will continue to improve the heavy oil production techniques either through our own efforts or in collaboration with advanced imported technology.

Figure 1
Artificial Lift by Bottom Water

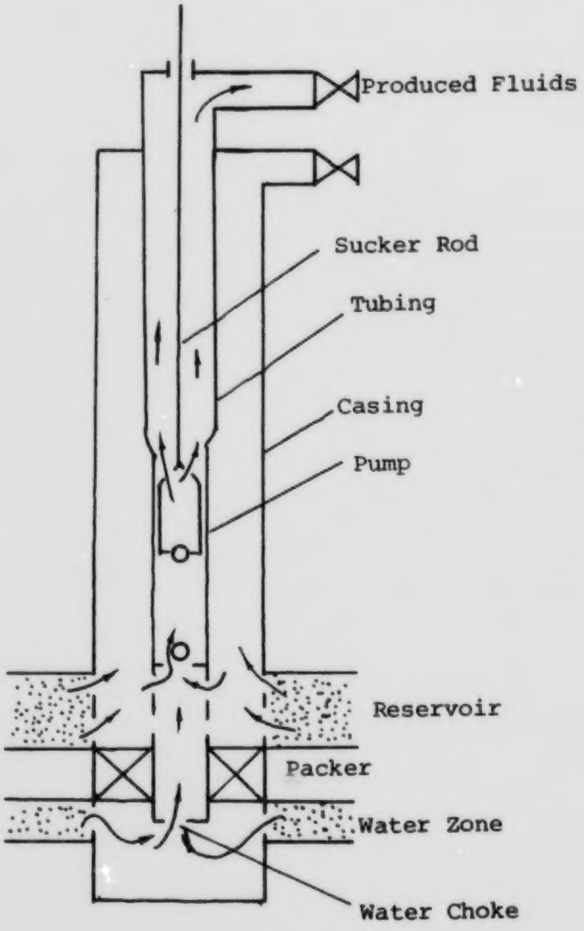

Produced Fluids
Sucker Rod
Tubing
Casing
Pump
Reservoir
Packer
Water Zone
Water Choke

Figure 2
Injection of Surfactant Solution

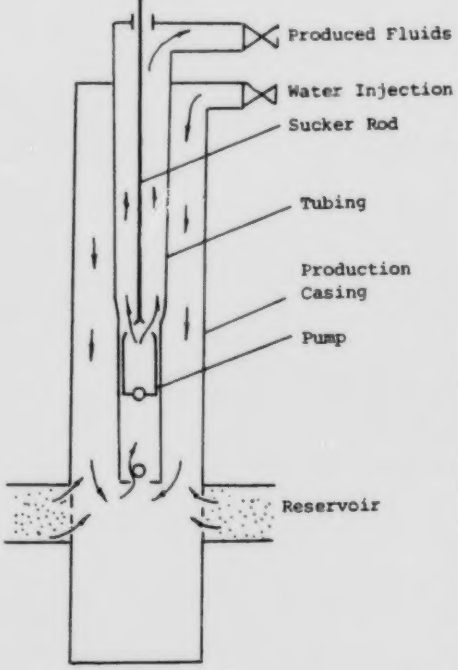
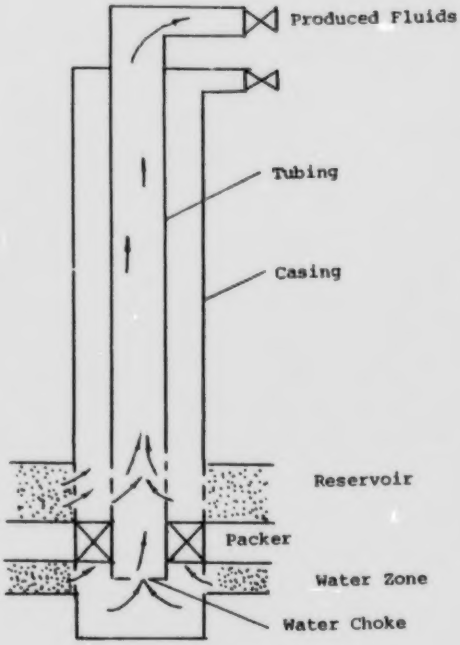

Produced Fluids
Water Injection
Sucker Rod
Tubing
Production Casing
Pump
Reservoir

Figure 3
Flowing Well


Produced Fluids
Tubing
Casing
Reservoir
Packer
Water Zone
Water Choke

14

THE DETERMINATION OF POLISHED-ROD LOAD IN PUMPING DEEP HEAVY OIL WELL

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ABSTRACT

This paper presents a method for calculating the polished-rod load in pumping deep heavy oil well. The proposed method includes the friction loss, which generally is neglected in the same calculation for light oil.

The friction loss is a function of oil viscosity, solution gas-oil ratio, pressure and temperature in the wellbore. The relationship between these parameters is illustrated. A field example by applying the proposed technique to the Gaosheng Oil Field is presented. The results showed the calculated and measured values are in a close agreement indicating that the proposed method is reasonable and dependable.

INTRODUCTION

Field applications have indicated that the polished-rod pumping system can be applied to the deep heavy oil only if the formation temperature and well productivity are high. For such applications, the method used for calculating polished-rod load for the light oil system is applicable only if the friction loss was taken into consideration. The friction loss will be a significant parameter in the determination of polished-rod load and must be accounted for[4, 5, 6].

The friction loss is a function of oil viscosity and solution gas-oil ratio, which in turn are related to the pressure and temperature in the wellbore. The relationship between these parameters is often complicated and must be evaluated carefully.

This paper develops a method which takes into account the friction loss when calculating the polished-rod load for pumping deep heavy oil. An example was applied to the Gaosheng Oil Field. The results of the calculated and measured values are in a close match indicating that the proposed method can be used to assist in the design and selection of polished-rod pumping system in deep heavy oil wells. This method can also serve as a useful tool to aid in analyzing the dynamometer and predicting the production performance.

BASIC FORMULAE AND CALCULATION PROCEDURES

1. Distribution of Temperature in the Wellbore

The conditions of heat-transfer in the wellbore vary with tubing length, tubing diameter, pump-setting depth and the fluid level in the annulus. Based on the method developed by Ramey et al[1], the following equations were derived to estimate the distribution of temperature in the wellbore (Appendix A):

EQUATION 1

$$T(z) = Ti.e^{-(Z/A)} - \alpha.z + (\alpha.A + \alpha.H + B)\ (1 - e^{-(Z/A)})$$

where

$$A = W.C.\,[K_1.R_t + r_1.f(t)\,]/2\,\pi\, r_1 k_1$$

$$f(t) = (\ln 2.\sqrt{x.t/r4}) - 0.29$$

$$R_t = r_2.1n(r_3/r_2)\,/K_2$$

Based on the conditions of heat-transfer in the wellbore, the estimation of the temperature distribution can be carried out in three distinct intervals: (1) from bottom hole to pump inlet, (2) from pump inlet to the fluid level in the annulus, and (3) from fluid level to wellhead. The temperature at the three reference points (at the bottom hole, at the pump inlet and at the fluid level in the annulus) must be estimated first, then the distribution of temperature in each interval can be determined by using Equation (1).

2. Oil Viscosity in the Wellbore

The viscosity of oil in the wellbore, which is mainly a function of temperature and solution gas-oil ratio, can be determined by using the following two empirical formulae:

a) For dead oil

$$\mu = \mu_o Tc^R$$

b) For live oil

$$\mu_g = A \mu^B$$

where

$$A = 10.75 (5.615 G + 100)^{-0.515}$$

$$B = 5.44 (5.615 G + 150)^{-0.338}$$

Because the gas-oil ratio is a function of pressure,the pressure distribution in the wellbore must be determined first.

3. Density of Liquid-Gas Mixture in the Wellbore

During the pumping process, the mixture of liquid and gas is moving along the wellbore, this makes the calculation of liquid density in the wellbore very complicated. Assuming the solution gas is has difficulty to bubble out of the heavy oil, then the density of the liquid-gas mixture may be estimated by the following equation as proposed by Podio[2].

$$G_m = G_{cf} . G_l$$

In order to determine the correction factor, G_{cf}, the flow rate of free gas in the tubing must be calculated first by using the following equations:

$$Q = C_z.Po.(Qp-Qs) .T_k / To.P$$

$$Qs = K.P.Wo/Go$$

The above equations indicate that the average pressure at a given interval should be known to determine the density of fluid in that interval. The density is a direct function of average pressure, therefore, a trial and error method may be used to solve these two unknowns simultaneously.

4. The Calculation of Polished-Rod Load (PRL)

The polished-rod load for pumping heavy oil can be calculated by the following equations:

For the upstroke:

$$P_{max} = P_r + P_l + P_{iu} + P_b + P_{fu} + P_d - P_{in}$$

For the downstroke:

$$P_{min} = P'_r - P_{id} - P'_b - P_{fd} - P_v - P_d$$

The definition of each term in the above equations is as follows:

1) P_r = weight of the rod string in air

$$P_r = q_r.L$$

2) P'_r = weight of the rod string in the fluid

$$P'_r = q_r.(r_s - \rho\ ) / r_s$$

3) P_e = weight of the fluid column in the tubing

$$P_l = (f_p - f_r) .L.\rho$$

4) P_{iu} = acceleration load in the upstroke

$$P_{iu} = (P_r + P_l.)\ . S.N^2/1790$$

where:

$$\varepsilon = (f_P - f_r)/(f_t - f_r)$$

5) P_{id} = acceleration load in the downstroke

$$P_{id} = P_r.S.N^2/1790$$

6) P_b = load due to back pressure at the well head during the upstroke.

$$P_b = P_t.(f_p - f_r)$$

7) P'_b = load due to back pressure at the well head during the downstroke.

$$P'_b = P_t.f_r$$

8) P_d = friction loss between the plunger and the working barrel.

$$P_d = [(1.65.Dp/\delta) - 127]. 1 /9.8$$

9) P_{in} = load due to pressure at the pump inlet.

$$P_{in} = [(Lo-H_y-F_h) .r + P_s].f_p$$

where:

$$Fh = (1/\lambda^2).((f^2{}_p(\pi.S.N/60)^2)/(f^2{}_o\, 2g))$$

The flow rate coefficent can be obtained from -R_e curves [4], where Reynolds number,

$R_e = (1/19)(d_o.f_p.S.N/vf_o)$

10) Friction loss in the upstroke, includes:

a) friction loss between the sucker rod and the fluid.

$$P_{u1} = (2\pi^2.v\rho..S.N.M_1.L/9.8).EE.RA$$

where:

$$M_1 = 1/((m^2+1)/(m^2-1)).(\ln m-1)))$$

$$m = dt/dr$$

$$EE = 1/((Q/W_o)+W_w+1)$$

$$RA = 1-(f_p-f_r)/(f_t-f_r)$$

b) friction loss between the rod coupling and the fluid.

$$P_{u2} = (2\pi^2.v\rho..S.N.M_2.L/9.8).EE.RA$$

where:

$$M_2 = 1/((m'^2+1)/(m'^2-1)).(\ln m'-1)))$$

$$m' = dt/dc$$

c) friction loss between the tubing and the fluid.

$$Pu3 = (P_{ul}/RA\ 1.3)$$

11) Friction loss in downstroke includes:

a) friction loss between the rod and the fluid

$$P_{d1} = P_{u1}/RA$$

b) friction loss between the rod coupling and the fluid

$$Pd_2 = P_{u2}/RA$$

It should be noted that in the previous calculations, the diameters of tapered tubing and sucker rod are often varied with depth, along with the viscosity and density of the mixture in the wellbore. Therefore, the calculations of the polished-rod load and of the viscosity and density should be carried out simultaneously for each interval. The total load is then the sum of all of the individual loads.

■ 5. Calculation Procedures

The calculation procedures for polished-rod load is straight forward. First, the temperature at the three reference points are estimated. Then for each given increment of pressure downward from the wellhead, the average pressure, temperature, density, viscosity, height and various loads at the corresponding interval are calculated by the trial and error method described below:

1) Assume the temperature at the top of the fluid interval as the average temperature. i.e. $T = T_1$

2) Use the average pressure and temperature at the fluid interval, and calculate the average density of the fluid, fluid column height and the temperature at the bottom of the fluid level.

3) For the first calculation of the bottom temperature, take $T=(T_1 + T_2)/2$, $T'_2 = T_2$ and go to Step (2), otherwise go to Step (4).

4) If $|T_2 - T'_2| \le \varepsilon$ (an allowable error), then go to Step (5), otherwise take $T = (T_1 + T_2)/2$,

$T'_2 = T_2$ and go to Step (2).

5) Calculate the viscosity, friction loss and other related loads.

6) For the next interval, take $T = T_2$, $T_1 = T_2$ and $P = P + \Delta P$, then go to Step (2) and repeat the calculations.

The previous calculation steps are repeated until the depth of the pump inlet is reached. The summation of all the individual loads at each column interval will be the polished-rod load.

RESULTS AND DISCUSSIONS

By using the above formulae and calculation procedures, the polished-rod load for thirteen pumping wells in the Gaosheng Oil Field was determined. Table 1 illustrates the comparison of calculated with the measured values. The results show that the majority of the wells have a close agreement indicating the proposed method is suitable for determining the polished-rod load. This method can also be used to assist in the analysis of dynamometer studies and the prediction of production performance.

CONCLUSIONS

- ☐ 1. *A reasonable method was developed to determine the polished-rod load for Gaosheng Oil Field and other heavy oil fields.*
- ☐ 2. *The proposed method can be used to aid in analyzing the dynamometer and predicting the production performance.*

- *3. The polished-rod load is sensitive to the gas-oil ratio, gas solubility, viscosity, temperature, pressure and the depth of the fluid level in the annulus. These parameters must be estimated accurately to determine a meaningful polished-rod load.*

NOMENCLATURE

H	Distance from the reference point to the surface, m
Ti	Wellbore temperature at the reference point, °C
z	Height above the reference point, m
B	Surface geothermal temperature, °C
α	Geothermal gradient, °C/m
T(z)	Wellbore temperature at z, °C
C	Specific heat of liquid in the wellbore, Kcal/kg-
K_1	Thermal conductivity of the formation, Kd cal/day-°C
K_2	Thermal conductivity of the fluid in the annulus, Kcal/day-m-°C
r_1	r_2, r_3, r_4 - inside and outside radius of tubing and casing respectively, m
X	Thermal diffusivity, m^2/day

@SS = tTime required for fluid temperature reaching stable, day

W	Production rate of liquid, kg/day
μ_o	Viscosity constant regressed from viscosity-temperature curve of oil determined in the lab, cp
R	An index regressed from viscosity-temperature curve of oil determined in the lab, dimensionless
Tc	Temperature in °C
G	Gas oil ratio, m^3/m^3

@SS = μ Viscosity of dead oil, cp

μ_g	Viscosity of live oil, cp
G_m	Density of mixture, kg/m^3
Gl	Density of fluid, kg/m^3
G_{cf}	Correction factor
K	Solubility of gas, m^3/m^3/atm
P	Pressure in atm
T_k	Temperature in K
P_o, T_o	Pressure and temperature at standard condition, atm and K
W_o	Oil production rate, kg/day
G_o	Density of dead oil, kg/m^3
Q_s	Volume of gas dissolved, m^3/day
Q_p	Gas production rate, m^3/day
Q	Flow rate of free gas at P and T, m^3/day
Cz	Compressibility of gas
Pr	Weight of rod string in the air, kg
Pr'^{1}	Weight of rod string in the fluid, kg
q_r	Unit weight of rod string, kg/m
L	Total length of sucker rod string, m
r_s	Density of sucker rod, kg/m^3
Pl	Weight of fluid column in the tubing, kg
fp	Gross plunger area, m^2
fr	Cross sectional area of sucker rod, m^2
Piu	Acceleration load in the upstroke, kh
S	Stroke length, m
N	Number of strokes per minute
ft	Tubing flowing area, m^2
ε	Fluid velocity coefficient, dimensionless
Pid	Acceleration load in the downstroke, kg
Pb	Load due to back pressure at the wellhead during upstroke, kg
Pb'	Load due to back pressure at the wellhead during downstroke, kg
Pt	Back pressure at the wellhead, kg/m^2
Pd	Friction loss between the plunger and the working barrel, kg
Dp	Diameter of plunger, m
δ	Gap between the plunger and the working barrel, m
Pin	Load due to the pressure at the pump inlet, kg
Re	Reynolds number, dimensionless
Fh	Friction loss due to fluid flowing through the standing value, kg
L_o	Pump-setting depth, m

@SS = H_vDepth of the fluid level in the annulus during pumping, m

P_s	Casing pressure, kg/m^2
r	Density of the fluid in the annulus, kg/m^3
f_o	Open area of standing value, m^2
g	Acceleration of gravity (=9.8m/sec^2)
λ	Flow rate coefficient, dimensionless
Pfu	Friction load during upstroke kg
Pu1	Friction loss between the sucker rod and the fluid in the wellbore during upstroke, kg
Pu2	Friction loss between the rod coupling and the fluid in the wellbore during upstroke, kg
Pfd	Friction load during downstroke, kg
Pd1	Friction loss between the sucker road and the fluid in the wellbore during downstroke, kg
Pd2	Friction loss between the rod coupling and the fluid in the wellbore during downstroke, kg
v	Kinematic viscosity of the mixture in the wellbore m^2/sec
ρ	Density of the mixture in the wellbore, kg/m^3
d_t,d_r,d_c	Inside diameter of the tubing, outside diameter of the rod and of the coupling respecively, m
W_w	Water cut, decimal
RA	Correction factor for the relative movement between the sucker rod and the fluid
EE	Percentage of oil volume in the mixture
Pmax	Maximum polished rod load, kg
Pmin	Minimum polished road load, kg

ACKNOWLEDGEMENT

The authors would like to thank Mr. Zhang Fenejiu for his contribution to this work.

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Table 1

Well No.		2-2-6	2-3-5	3-4-0122	3-5-061	3-1-051	3-1-0102	2-3-06	2-2-082	3-4-132	3-4-92	3-5-92	3-5-0112	3-6-102
	D.V.	6984	3686	7985	6014	5820	7945	7020	10215	6356	6129	5902	7718	7491
	C.V.	7031.6	3674.3	8023.5	5906.5	5813.6	8143.9	7398.8	8894.2	6475.1	6526.5	5811.4	7727.7	7408.3
Maximum PRL (kg)	$\frac{D.V.-C.V.}{D.V.} \times 100\%$	0.68%	0.31%	0.48%	1.79%	0.11%	2.50%	5.40%	12.93%	1.87%	6.48%	1.53%	0.13%	1.10%
	D.V.	1940	2134	1932	1940	2134	681	2243	3859	3178	2497	3724	3178	3078
	C.V.	1942.2	1807.4	2019.6	1896.2	1518.2	651.8	1935.2	3345.0	2925.3	2855.3	3485.5	3370.4	3112.7
Minimum PRL (kg)	$\frac{D.V.-C.V.}{D.V.} \times 100\%$	0.11%	15.3%	4.53%	2.26%	28.86%	4.3%	13.72%	10.73%	7.95%	14.35%	6.40%	6.05%	1.13%

Note: In the table, D.V. stands for dynegraph value. C.V. for calculated value

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APPENDIX A

DERIVATION OF TEMPERATURE DISTRIBUTION IN THE WELLBORE

As shown in Figure 1, let us assume a reference point at the depth of H, where the fluid temperature is T_i. At Z level upward from this point, assume the temperature of the mixture is T(Z), the temperature at casing wall is T'(Z), then based on the principal of heat-transfer, the heat loss by liquid in the wellbore should be equal to the heat transferred to the casing, therefore:

$$dq = W.C.dT(z) = 2.\pi r_1 .U. [T(z) - T'(z) dz \qquad (1)$$

and the heat transferred from casing to formation is

$$dq = 2 .\pi . K_1 [T'(z) - T''[z]/ f(t) . dz \qquad (2)$$

Where

$$T''(z) = \alpha. (H - z) + B$$

(3) Eqs. 1 and 2 may be written as:

$$T(z) - T'(z) = dq / (2. \pi r_1 . U . dz) \qquad (4)$$

and

$$T'(z) - T''(z) = dq / (2. \pi .K_1. dz) . f(t) \qquad (5)$$

Eliminate T'(z) from Eqs. 4 and 5 yeilds:

$$dq = [T(z) - T''(z)] . dz/ [1/(2. \pi r_1 .U) + f(t) /(2. .K_1)$$

(6)

Eqs. 1 and 3 may be substituted in Eqs. 6 to yield.

$$-W.C. dT(z) = [T(z) - (H-z) -B] .dz/[1/(2. \pi .\rho_1.U) +f(t) /(2. .K_1)]$$

(7)

Let

$$A = W.C.[K_1 + r_1.U.f(t)]/(2. \pi .\rho_1.U.K_1)$$

Then Eq. 7 becomes

$$dT(z) /dz + T(z) /A-\alpha .(H-z) + B/A = 0$$

(8)

The solution of Eq. 8 is

$$T(z) = (\alpha .H+B) - \alpha .z + .A + c.EXP(-z/A)$$

(9)

For z = 0,

$$T(z) = T(O) = Ti, T''(z) = T''(O) = .H + B$$

Thus

$$c = Ti - .H-B- .A \qquad (10)$$

substituting Eq. 10 into Eq. 9 yields

$$T(Z) = Ti.e^{-z} A - .z + (.A+ .H+B) (1-e^{-z} A)$$

Where U, an over-all heat transfer coefficient between tubing and casing can be evaluated by

$$U = K_2/[r2.1n(r3/r2)]$$

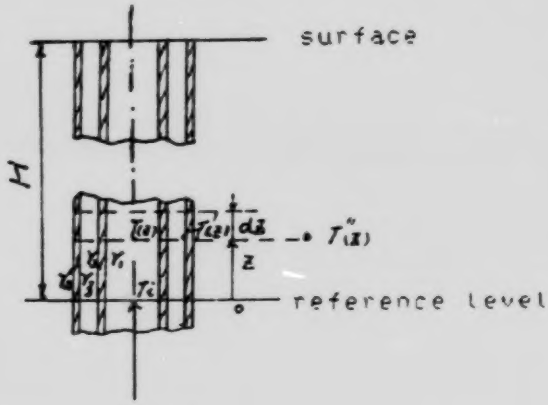

Fig. 1

APPENDIX B

CONVERSION BETWEEN ENGLISH UNITS TO ENGINEERING UNITS

t °C = (9/5*t+32) °F
1 m = 3.048 ft
1Kg = 2.205 lb
1 atm = 0.0703 psi
1 kcal = 3.968 Btu

15

SUCKER ROD PUMPING SYSTEM FOR CYCLIC STEAM STIMULATION PROJECTS

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ABSTRACT

One string sucker rod pumping system has been developed for pumping heavy oil from bottom hole for the cyclic steam stimulation operation. In designing a sucker rod pump, consideration was given to facilitate steam injection operation. A large scale field application of the pump system had been conducted to verify the reliability and advantages of the system under various field conditions. This article delineates the working principle and characteristics of the technique and discusses the mechanical structure of the sucker rod pumping system along with its cost effectiveness.

INTRODUCTION

Production technology is being continually improved as more heavy oil fields in China are developed. Since early 1984 when we began experimentation of cyclic steam stimulation at Karamay No. 9 heavy oil field, many research activities have been carried out to improve the sucker rod pumping system for heavy oil production. During the past three years, we have conducted preliminary tests on 15 wells. These data were used to further improve the pump system which was subsequently tested on 43 wells. These tests demonstrated that with the sucker rod pump in place, the productivity of the cyclic steam stimulation operation was significantly improved while the production costs reduced. The tests also verified the adaptability of the system under various field conditions. Since the test results were encouraging, the pump system has been accepted by national standard as a production practise for cyclic steam stimulation operations.

PRODUCTION CONDITIONS AT KARAMAY OIL FIELD

The Karamay No. 9 oil field is characterized by shallow wells of about 200 to 250 meters deep, low GOR, relatively good fluid properties and excellent fluid viscosity response to temperature. Production operations are characterized by short flowback period, long pumping production period and high wellhead pressure. Typically, wells are steamed for about 7 to 16 days for a total steam quantity of about 1,200 to 2,000 tons, and are allowed to flowback for about 5 to 30 days. According to the statistics of the production data from 27 well, average flowback period was 16 days which is considered quite short. Some wells flowbacked only a very small quantity of water while others did not flowback at all.

As a result of short flowback period, bottom hole temperature is very high, about 160° C. Since the heavy oil from the No. 9 oil field is very sensitive to temperature, the oil becomes quite viscous during the six cold months from the end of fall to early summer. The viscous oil is more difficult to transport due to high friction loss and back pressure in production lines. Back pressure at wellheads is typically 3 to 10 atmospheric pressure during these months.

Before the sucker rod pumping system was developed, well workover was required to lower a pump to a bottomhole for switching a well from flowback to production stage. Due to high bottom hole temperature and back pressure in production tubing, blow out from the workover well sometimes occurred. To prevent well blow-out, 15 to 30 m^3 of fresh water was injected to overcome bottom hole pressure. This practise was far from safe, as well blowout still occurred resulting in injuries to crewmen by the blown out hot water. The following problems are associated with the conventional well pumping technique:

1. Well workover delayed production schedule.

2. Fresh water used during well workover for preventing well blow out lowered reservoir temperature and contaminated the formation.

3. .Unsafe working conditions for workover crewmen, and

4. Well workover was costly.

The above problems associated with conventional well pumping technique are unacceptable to cyclic steam stimulation operations. Since 1984, efforts have been devoted to the development of the sucker rod pumping system which requires no well workover and which is found to improve productivity of cycle steam stimulation operations considerably.

WORKING PRINCIPLE AND STRUCTURE OF SUCKER ROD PUMP

As shown in Figure 1, the structure and components of a sucker rod pumping system consists mainly of a wellhead, sucker rod, production tubing, Model 843 injection-production dual purpose pump and perforated pipe. Wellhead is equipped with a stuffing box, choke valves, production tubing ring and casinghead. The Model pump consists of a plunger (6), working barrel (7), steam injection connector (8), fixed valve ball (9) and safety connector (10).

Model 843 pump is installed in wellbores in a similar procedure as the conventional workover practices. The pump is lowered to a desired depth in a wellbore. The exact position of the pump is determined by measuring the length of the pump rod. Precaution must be taken to avoid setting the plunger into the pump barrel; instead it should be positioned about 4.8 meters above the pump barrel by raising the horsehead at wellhead for steam injection. At the end of steam injection, the well is allowed to flowback by closing the steam valve and opening production valve. To switch the well to pumping, the seal box at the wellhead is loosened, and the pump plunger is allowed to lower to the pump barrel by cutting off the shear pin. The following operating features of the pump are noted:

- *The Model 843 pump provides same performance as the conventional pumps but it is more adaptable under various field conditions.*
- *The pump is designed for temperature specification of 350° C at 200 atmospheric pressure. At room temperature, the pump can withstand up to 250 atmospheric pressure.*
- *Safety connector of the pump can be used for oil drainage during well workover.*
- *The system requires no well workover to switch well operations from steam injection, flowback to pumping stages.*
- *The installation is simple and safe. It is easy to operate.*

FIELD TESTINGS AND APPLICATION

Fifteen field tests had been conducted, eleven of which involved Model 843 pumps. By the end of November, 1986, the one string sucker rod pumping system had been applied to 43 wells. The pump was tested to the maximum temperature of 329° C, maximum pressure of 116 atmospheric pressure, maximum steam flow rate of 306 tons/day and maximum cumulative steam quantity of 2,915 tons. Testing of the pumps had accumulated a total steam injection quantity of 92,676 tons, flowback liquid production of 12,892 tons, flowback oil production of 5,813 tons, pumping liquid production of 75,792 tons and pumping oil production of 49,732 tons. The field testing had successfully accomplished the complete well operating cycle from steam injection, flowback to pumping on 55 well cycles. During the testing period, the pumps in two wells were found to be inoperative due to falling objects; and one due to misplaced liner.

Some of the pumps were retrieved for inspection after the tests. With the exception of a few valve balls which were eroded in a similar manner as a conventional pump, no corrosion and material deformation was found by the inspection on pump barrels, plungers and valve seats. The retrieved pump plunger, after it was thoroughly cleaned, was found to fit as snugly inside a liner as it was before the field tests. The dimensions of the pump plunger and liner were measured and found to be the same as before the tests. The pumps also passed the leakage tests as required by a class I pump. The pumping system is simple and easy to operate. The field testings and application had proven its reliability and safety.

ANALYSIS OF COST EFFECTIVENESS

Preliminary analysis for the cost effectiveness of the sucker rod pump system was conducted based on the data from field testings and application. The pump system would eliminate a 2.5 inch valve per well and save about 1,000 yuans. Saving in workover of a 200 meter well at Karamay No. 9 Oilfield is estimated to be 2,000 yuans per production cycle. The saving would be greater for a deeper well. With the sucker rod pump system, no workover is required to switch well from flowback to pumping, production could begin immediately after flowback and would not be affected by the fresh water used during the workover which would lower formation temperature and pose oil/water emulsification problem. Statistics on the field data indicates that workover of a well normally takes 3.3 days; and a Model 843 sucker rod pump produces 48.9 tons/day of liquid and 23.6 tons/day of oil. A three day workover job would lower production by 70.8 tons according to the above production statistics.

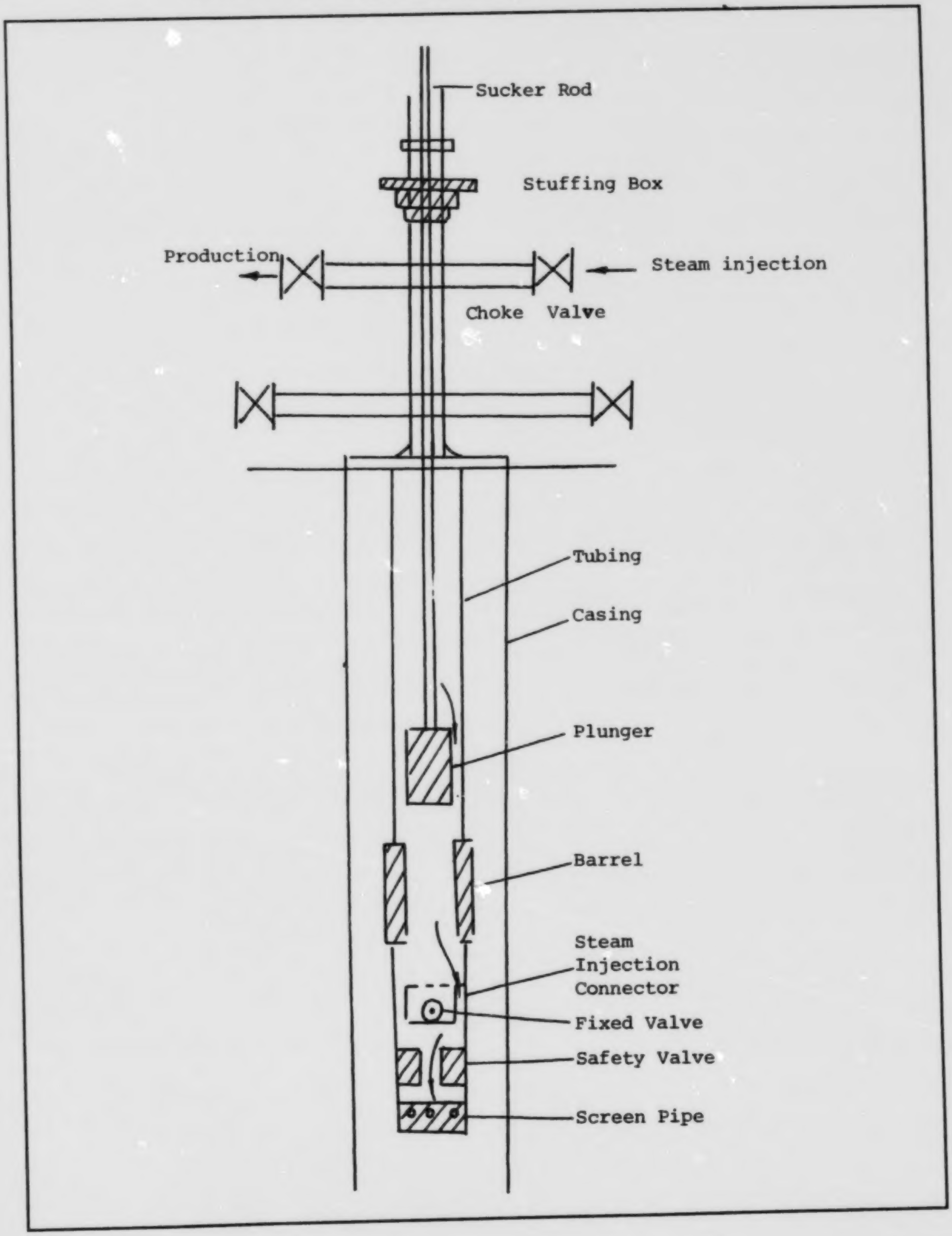
Workover of a well at Karamay No. 9 oilfield normally requires 20 cubic meters of fresh water on the average, which lowers temperature of the formation surrounding the wellbore. Production tubing wall is cooled and oil viscosity can reach as high as 1,700 cp as a consequence. The oil becomes immobile and well production low until the production tubing is gradually heated up.

For a qualitative analysis, production data from 44 wells equipped with conventional pump are compared with those from 11 wells equipped with sucker rod pump operated under similar conditions such as steam injection volume, steam injection intensity(steam quantity/reservoir thickness), steam quality and reservoir effective thickness. Preliminary comparison indicates that production increased by the sucker rod pumps over the conventional pump was 126.5 tons during the first month, 79.6 tons the second month and 131.3 tons the third month. The effectiveness of the sucker rod pump diminished after the third month. As a matter of fact, the subsequent production by the conventional pump was slightly higher as a result of the better quality reservoir. Overall increase in production by the sucker rod pump amounted to 323.8 tons or 12.6 % for the entire pumping period. For the entire production cycle including flowback, the increase was lower, about 199 tons or 7.7 %. The cost effectiveness of the sucker rod pump is summarized as follows:

Capital Cost Saving	1,000 yuans
Saving in Workover	2,000 yuans/well
Production Increase	199 tons/cycle/well

It is obvious from the above comparison that the economic benefits from applying sucker rod pump is quite impressive. Of course, the above analysis can only be regarded as preliminary because of the limitation in the amount of valid production data for the analysis. A sound quantitative analysis can only be conducted when better quality and larger amount of field data are available. The present study nonetheless concludes that the sucker rod pump is cost effective and should be widely used at the Karamay No.9 oilfield.

Figure 1
Structure and Components of a Sucker Rod Pumping System


Sucker Rod
Stuffing Box
Production
Steam injection
Choke Valve
Tubing
Casing
Plunger
Barrel
Steam Injection Connector
Fixed Valve
Safety Valve
Screen Pipe

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SPECIALLY DESIGNED PUMPS FOR HEAVY OIL PRODUCTION

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ABSTRACT

Heavy oil production is complicated by the fact that the prime controlling variable is viscosity. The viscosity of clean oil is easily measured in the laboratory; however, the actual fluid viscosity in the pumping system varies widely. The effective viscosity can range from 1 cp to 20,000 cp and beyond, depending on such factors as watercut, entrained natural gas, and the emulsion characteristics. The effective viscosity cannot be accurately determined in a pumping system prior to the installation of the system. Therefore, a more empirical approach is used to determine the optimum choice of pumping equipment.

Many different pumping systems have been installed and tested in the Lloydminster heavy oil area. The most successful systems are discussed in this paper. Emphasis is placed on their advantages and disadvan tages. Recommendations, based on individual well characteristics, are presented on which system will result in the optimum performance.

Conventional pumping equipment, progressive cavity pumps, hydraulic pumpjacks, and vertical hydraulic units are evaluated.

INTRODUCTION

This paper consists of a performance comparison of the major pumping systems used in the Lloydminster, Alberta, Canada heavy oil area. Many other pumping systems - continuous cable, automatic bailer, etc. - have been tested and proven unsuccessful for heavy oil production.

Photographs of the pumping system are shown in Figures 1 - 5.

Five surface pumping systems are discussed. However, there are only two basic bottomhole pumps: the conventional pump (Figure 6) and the progressive cavity pump (Figure 7).

Since the current prices are changing rapidly, no attempt was made to compare the purchase costs of the different systems.

DISCUSSION

■ Fuel Efficiency

The most fuel-efficient pumping system is the conventional pump with conventional pumpjack. The counterbalance supplied by the crank arms and weights significantly reduce the horsepower required to operate the system. The weights are raised during the downstroke with assistance fro the ro load. The weights fall during the upstroke and the potential energy of the weights inputs power into the system.

The hydraulic pumpjack and vertical hydraulic unit offer less fuel efficiency.

The progressive cavity pump with direct drive has high fuel requirements. The system does not have the counterbalance efficiency of the conventional pumpjack. In addition, more horsepower is lost in overcoming the viscosity of the produced fluid. The rods are moving by the viscous oil at a higher average velocity when using a progressive cavity pump. The increased shear rates result in a higher horsepower requirement.

The poorest fuel efficiency is evident with the progressive cavity pump with hydraulic drive. This system has all the disadvantages of the progressive cavity pump plus the inefficiency of converting mechanical power to hydraulic power and then back to mechanical power. Indeed, a fuel requirement increase of over 200% has been noticed when replacing a conventional pumpjack with a hydraulic drive progressive cavity pump.

■ Flexibility

The progressive cavity pump with the hydraulic drive is the most flexible system. The pump rpm can be easily changed throughout the entire operating range by simply adjusting a control knob. The hydraulics involved are simple and have been proven reliable over many years. Rod fall problems - a common condition in heavy oil production - do not exist when using a progressive cavity pump.

Moderate flexibility is available with the hydraulic pumpjack and the vertical hydraulic unit. The stroke length can easily be adjusted with the controls. In addition, the time spent during the upstroke can be set independently of the downstroke time. This will result in increased pump capacity when rod fall problems exist. However, it must be noted that this flexibility is limited since the downstroke time will still be identical to that of the conventional pumpjack. The pump capacity can only be improved up to a theoretical factor of 2.0.

The progressive cavity pump with Direct Drive has only moderate flexibility. The rod fall problems do not exist. However, the turndown ratio is limited to the speed range available on the engine. Outside of this range, the rpm can only be adjusted by changing the sheaves on the unit.

The least flexibility is noted when using the conventional pumpjack. Road fall problems are likely to exist and the available strokes per minute are directly related to the downstroke time. The downstroke time is usually the limiting factor. Some flexibility is available by varying the engine rpm and by changing sleaves. There are usually three choices of stroke length on each unit; however, changing stroke length requires shutting down the unit and the use of a labour crew and equipment.

■ Shutdown Control

As a minimum, all units should shut down on a high surface pressure condition to protect personnel and equipment. In addition, the progressive cavity pumps should shut down on a high surface torque situation to prevent severe damage to the rod string.

A variety of high surface pressure shutdowns are available - some are very reliable and some less reliable. However, the high pressure shutdown is mounted on the flowline and connected to the prime mover. As such, it is independent of the particular system in use.

The progressive cavity pump with hydraulic drive has excellent shutdown control for a high torque condition. The hydraulic system can easily be set to shut down at any chosen surface torque. The control has proven reliable and convenient.

The high torque shutdowns currently available for the progressive cavity pumps with direct drive are suspect and prone to failure. It should be recognized that this problem could result in a damaged rod string.

The vertical hydraulic unit and the hydraulic pumpjack have a shutdown advantage over the Conventional Pumpjack. They can be set to shut down at a predetermined rod load. This is difficult and expensive to do with a conventional pumpjack.

INDIVIDUAL WELL CHARACTERISTICS

The pumping equipment performance relative to individual well characteristics and servicing costs is a function of the downhole pump type only. Therefore, the performance comparison is between the progressive cavity pump and the conventional pump.

☐ *a. High Viscosity Oil Production*

The progressive cavity pump consistently shows superior performance for higher viscosity oil production. The pump has performed very satisfactorily when pumping viscous oil at surface installations. Its downhole performance has proven reliable also. The progressive cavity action provides improved fluid entry into the pump and results in a more consistent, stabilized production rate. It is very important to provide a stabilized production rate during heavy oil production. If the oil production stops for any reason, the sand suspended in the heavy oil in the tubing will settle out and fall on the pump. The pump will become "sanded in" and a service job will be required.

The conventional pump has problems dealing with very high viscosity oil production:

- *(i) There is poor fluid entry into the pump. It is difficult for the viscous fluid to flow through the standing valve and enter the pump chamber. The pump chamber is then filled with a small amount of oil and a relatively large amount of low pressure gas. On each stroke, the plunger must compress the gas to a pressure greater than the fluid column above the traveling valve before the traveling valve can open and the pumping process can take place. This results in very poor pump efficiency at the least. Indeed, the point is often reached where the traveling valve barely opens and the all too familiar "gas lock" condition occurs. Both the poor efficiency and the gas lock condition can result in an upward oil velocity in the tubing which is less than* *the settling velocity of the sand suspended in the oil. The sand will fall out on top of the pump, all pumping will cease, and a service job will be required.*

- *(ii) Serious rod fall problems occur during viscous oil production with a conventional pump. During the downstroke, both the buoyant force and the oil viscosity restrict the downward movement of the rods. It is common for the rod load at the surface to reach zero and the rod string to "free fall" during the downstroke. Obviously, this severely restricts the strokes per minute available with the pumping system. Maximum strokes per minute of less than one are common. The rod fall problems can result in both the inability to obtain maximum production from the well and in service jobs due to low upward oil velocity in the tubing.*
- *Some relief from the viscous effect on rod fall problems has been achieved by installing larger tubing in the well. This viscous effect on the rods is a function of shear rate. Therefore, an increased distance between the rod string and the tubing results in better rod fall characteristics. However, it should be note that a higher production rate is required when using larger tubing in order to achieve the minimum upward velocity in the tubing to avoid the sand fallout condition.*

☐ *b. High Sand Production*

The progressive cavity pump is far superior to the conventional pump on high sand production wells. The design of the progressive cavity pump provides a positive suction and a flushing action through the pump, both of which tend to improve the sand handling capability of the pump. In addition, the metal rotor matched to the rubber stator provides some flexibility during the movement of sand grains through the pump.

The conventional pump has difficulty handling high sand production. It can perform adequately when the high sand production is matched with a high production rate of relatively low viscosity oil and where the sand is evenly suspended in the oil. The design of the conventional pump leaves "dead spots" in the pump where sand readily accumulates. Many different valve designs have been tested with very little success in alleviating the problem. Also, the metal-to-metal contact between the plunger and the pump barrel provides little flexibility when pumping sand grains. A minor amount of sand can become wedged between the plunger and the pump barrel. The plunger will not be able to fall to the bottom of the stroke. Therefore, a small amount of sand can result in a costly service job when using a conventional pump.

☐ *c. Low Oil Production (0-2 m^3/day)*

The progressive cavity pump has a sRgnificant advantage over the conventional pump for low oil production wells. The progressive cavity pumps can operate over a wide rpm range. They can be easily adjusted for the maximum oil production the reservoir can deliver. Fluid levels can be taken to determine the point at which the reservoir inflow reaches its upper limit. The rpm is then set to allow continuous, stabilized production at the desired rate. This results in the best upward oil velocity in the tubing and decreases the risk of servicing problems caused by sand fallout. Also, the positive suction of the pump allows the pump to fill at the very low wellbore pressures associated with low oil production.

The capacity of the conventional pump is more difficult to adjust to match the well inflow characteristics. Also, poor fluid entry in the pump barrel at low wellbore pressures increases the risk of a "gas lock" condition and the subsequent servicing costs.

☐ *d. High Watercut Production*

The conventional pump is superior to the progressive cavity pump on wells producing oil at a high watercut, provided that a high viscosity emulsion does not exist in the wellbore. The conventional pump can now operate in a situation for which it has been designed. The major problems associated with heavy oil production by a conventional pump - poor rod fall and poor fluid entry into the pump barrel - do not exist. The low viscosity of the fluid in the tubing eliminates the rod fall problem and the low viscosity fluid easily enters the pump barrel.

The progressive cavity pump encounters a problem with high watercut production. The pump requires some lubrication from the produced fluids to prevent excessive pump wear. High watercut production does not supply the necessary lubrication. High maintenance costs can occur when attempting to produce high watercut wells with a progressive cavity pump.

☐ *e. High Gas/Oil Ratio Production*

Both the progressive cavity pump and the conventional pump can have problems when installed in wells producing at high gas/oil ratios. The conventional pump does perform better than the progressive cavity pump under this condition. The conventional pump will have a tendency to "gas lock" and problems can result. However, the lack of lubrication during high gas production through a progressive cavity pump results in excessive wear and usually more than offsets the problems experienced with the conventional pump.

When using either pump for high production wells, it is considered essential to minimize the amount of gas produced through the pump. This can be accomplished by using the annular space between the tubing and the casing as a gas/oil separator. The pump should be landed below the perforated interval. The production entering the casing will separate. The gas will flow up the annular space where it can be bled off and used for lease fuel. The liquid will drop and enter at the pump suction. It is critical not to "overpump" a high gas producing well. If the pump capacity exceeds the liquid inflow from the reservoir, all available liquid will be removed from the wellbore and gas will be present at the pump suction. This will result in "gas lock" or severe pump wear.

❑ *f. High Oil Production Well (8 m^3/day)*

Heavy oil wells which produce at high rates usually have relatively low viscosity fluid in the wellbore. The low viscosity can be due to lighter oil or entrained natural gas in a heavy oil stream.

The conventional pump performs better than the progressive cavity pump in this condition, although the performance of the progressive cavity pump is also acceptable. The conventional pump is again operating in a situation it has been designed to handle. The lower fluid viscosity eliminates the rod fall and pump fluid entry problems. The conventional pump can achieve higher capacities than the normal progressive cavity pump and can also operate with less wear under high fluid production conditions.

❑ *g. Servicing Cost*

The progressive cavity pump, when operated under the proper conditions, usually results in lower servicing costs than the conventional pump. The major servicing problem associated with heavy oil production is caused by sand. The progressive cavity pump is superior in handling sand production. Also, when a "sand-in" condition does occur, the rotor can usually be worked free from the strator and held above the strator while the tubing and pump are flushed free of sand. The rotor is then reset in the strator and production can resume. When a "sand-in" condition occurs with a conventional pump, it is quite often impossible to pull the plunger out of the pump barrel due to sand buildup over the plunger. Also, it can be difficult to screw onto and pull the standing valve due to sand buildup on it. Either condition requires pulling the rods and tubing from the well, cleaning or replacing the pump, and running the equipment into the well before production can resume. It can easily be seen that servicing tends to be less expensive when using a progressive cavity pump.

❑ *h. Pump Repair Costs*

When pump repair is required, the progressive cavity pump is significantly more expensive than the conventional pump and, indeed, it is more expensive to purchase initially.

The progressive cavity pump consists of only two parts: the rotor and the strator. If either part is worn or defective, that part must be replaced entirely. On the other hand, a conventional pump can often be reconditioned by replacing only minor parts, such as the valve seats and balls.

CONCLUSION

All of the systems discussed have been proven to be reliable for heavy oil production. However, they are reliable when, and only when, matched properly with the individual well characteristics. Table 1 shows a summary of the comparison of the pumping systems. At times, the most effective system changes during the life of an individual well. For example, a well which initially produces viscous, sandy oil at a low rate and later produces less sand a high watercut will operate more efficiently at first with a progressive cavity pump and later with a conventional pump.

When choosing a pumping system, it is important to consider the individual well characteristics, fuel costs and availability, desired flexibility, required control, an anticipated operating costs.

Table 1

Production Equipment Comparison

Progressive Cavity Pump With Hydraulic Drive	Progressive Cavity Pump With Direct Drive	Conventional Pump With Conventional Pumpjack	Conventional Pump With Hydraulic Pumpjack	Conventional Pump With Vertical Hydraulic Unit
1. Very high fuel usage.	1. High fuel usage.	1. Low fuel usage.	1. Moderate fuel usage.	1. Moderate fuel usage.
2. Most flexible system.	2. Moderate flexibility.	2. Minor flexibility.	2. Moderate flexibility.	2. Moderate flexibility.
3. Good shutdown control.	3. Poor shutdown control.	3. Moderate shutdown control.	3. Moderate shutdown control.	3. Good shutdown control.
4. Good performance on heavy oil, sandy, low producers.	4. Good performance on heavy oil, sandy, low producers.	4. Poor performance on heavy oil, sandy, low producers.	4. Poor performance on heavy oil, sandy, low producers.	4. Poor performance on heavy oil, sandy, low producers.
5. Poor performance on high watercut & high GOR producers.	5. Poor performance on high watercut & high GOR wells.	5. Good performance on high watercut wells. Moderate performance on high GOR wells.	5. Good performance on high watercut wells. Moderate performance on high GOR wells.	5. Good performance on high watercut wells. Moderate performance on high GOR wells.
6. Moderate performance on high oil producers.	6. Moderate performance on high oil producers.	6. Good performance on high oil producers.	6. Good performance on high oil producers.	6. Good performance on high oil producers.
7. Lower servicing costs.	7. Lower servicing costs.	7. Higher servicing costs.	7. Higher servicing costs.	7. Higher servicing costs.
8. Higher pump repair costs.	8. Higher pump repair costs.	8. Lower pump repair costs.	8. Lower pump repair costs.	8. Lower pump repair costs.

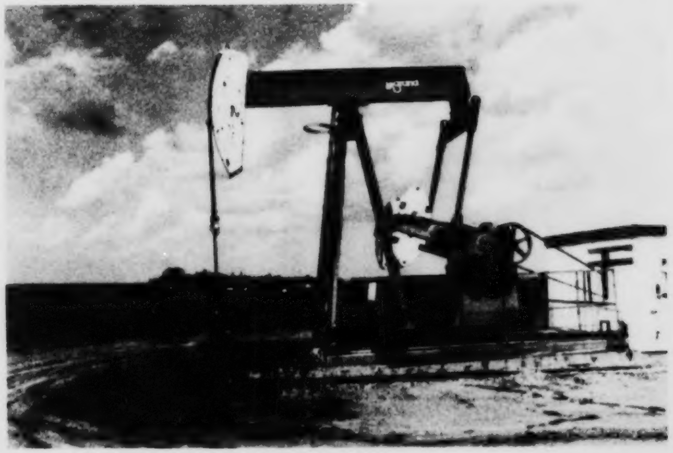

Figure 1 Conventional Pumpjack

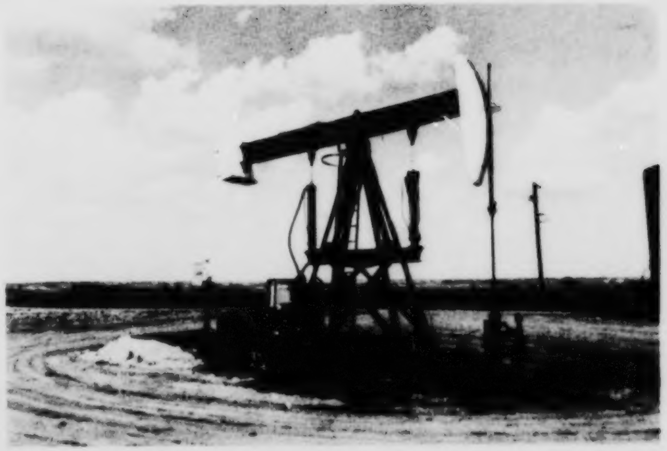

Figure 2 Hydraulic Pumpjack

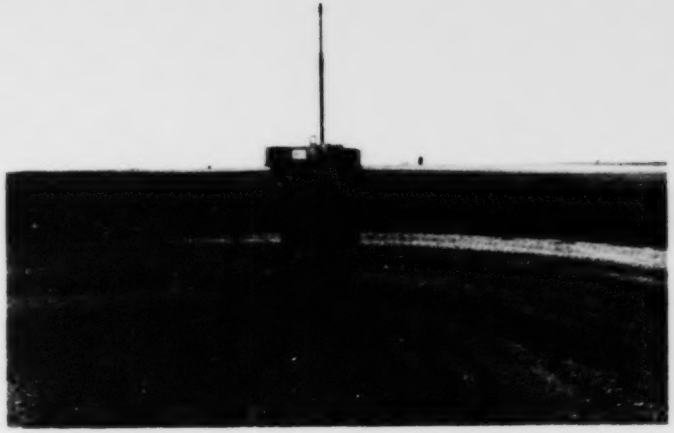

Figure 3 Progressive Cavity Pump with Hydraulic Drive

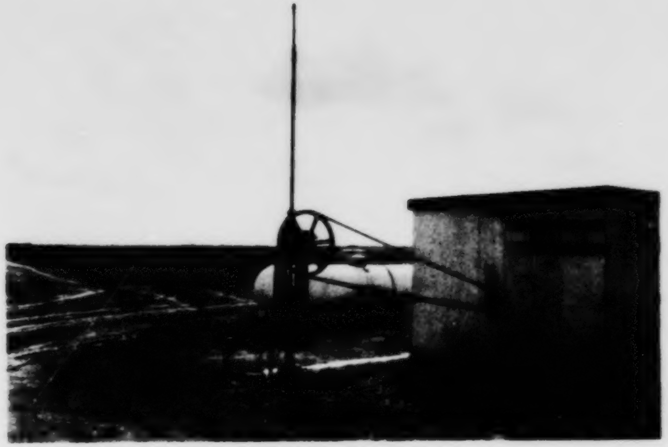

Figure 4 Progressive Cavity Pump with Direct Drive

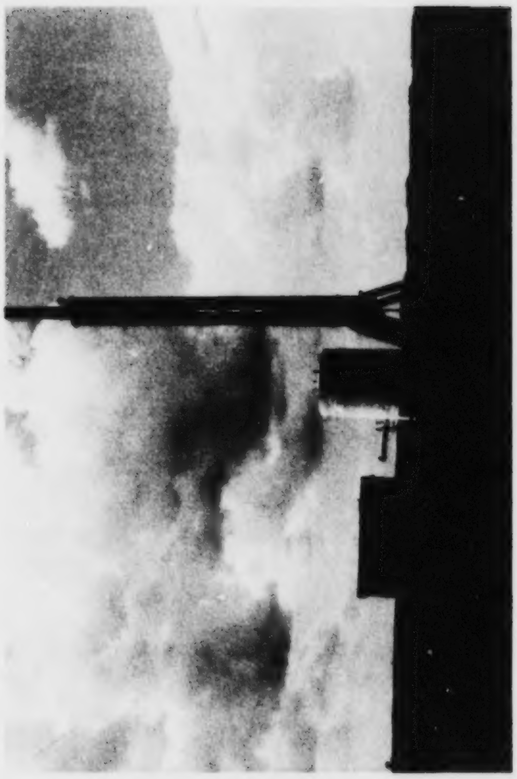

Figure 5 Vertical Hydraulic Unit

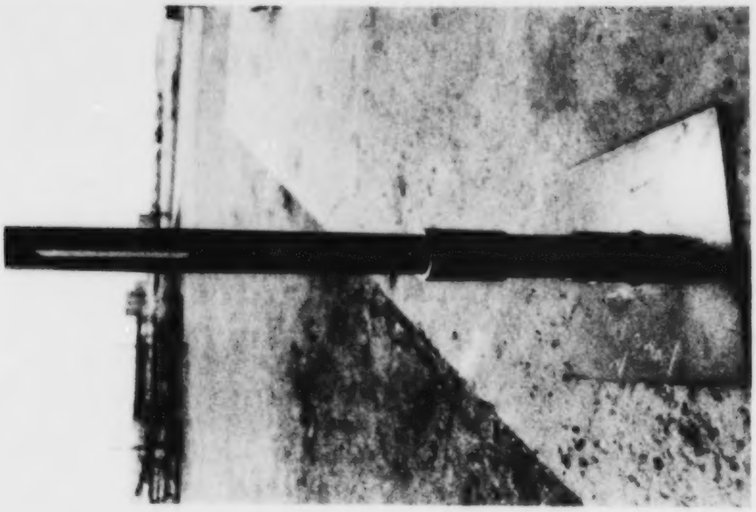

Figure 6 Conventional Pump

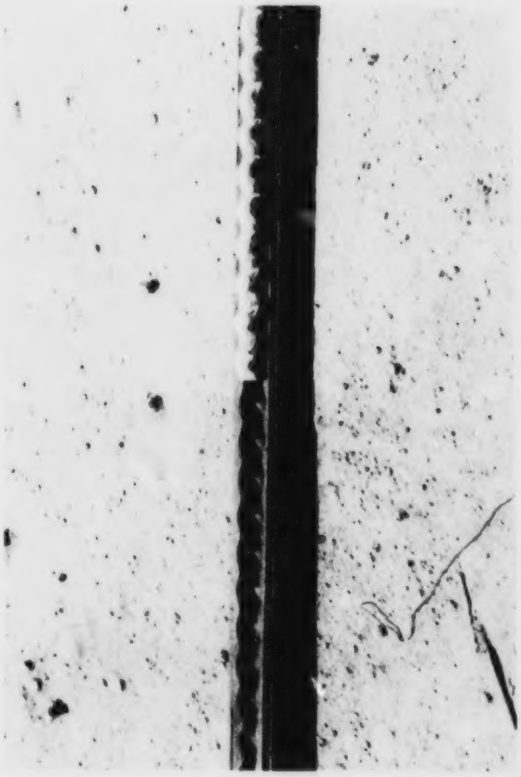

Figure 7 Progressive Cavity Pump

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THERMODYNAMICS AND COLLOID SCIENCE APPLIED TO OIL SANDS AND HEAVY OILS

Loren G. Hepler
University of Alberta

ABSTRACT

Thermodynamic properties of conventional petroleum, of substances used in upgrading and refining, and of the desired products have been used in many ways for many years. Similar applications can be equally useful in connection with upgrading and refining bitumens and heavy oils that contain high molecular weight components and substantial amounts of sulfur and other troublesome elements.

Thermodynamic properties of bitumen and heavy oil, along with properties of reservoir minerals, are also important with respect to thermal methods of production.

Thermodynamic data are often applied to many problems that are connected with the production or processing bitumen and heavy oil. Examples include water treatment and boiler water chemistry, chemical reactions of water or steam with minerals, coke treatment and utilization, treatment of waste waters and of oil sands tailings, and control of sulfur-containing emissions.

Colloid and surface properties are important in most aspects of petroleum technology. Examples include interfacial properties of petroleum-mineral-water systems in reservoirs, catalysts used in upgrading andrrefining, and water tailings treatment processes.

Examples to illustrate the subjects mentioned above are listed. In addition, there is more detailed discussion of a few specific applications, with emphasis on recent research done in Alberta.

INTRODUCTION

The research to be described here has been intended to contribute to practical solutions to a variety of technical problems relate to the oil (tar) sands and heavy oils in Alberta. This research was started at the University of Lethbridge and has been continued recently at the University of Alberta, all with support from the Alberta Oil Sands Technology and Research Authority (AOSTRA). Many of the people who have done this research with me are identified as co-authors of various publications that are cited at the end of this paper.

HEATS OF COMBUSTION

It has been known for a long time that calorimetrically measured heats of combustion are directly useful for assessing the "fuel values" of various substances (different kinds of oil, bitumens, pitches, cokes, etc.). This kind of information is necessary for making rational decisions about the best uses (burning to obtain process heat, upgrad- ing to a more useful liquid, etc.) of such substances. It is for these reasons and also to obtain information to be used in connection with in situ combustion processes that we have made heat of combustion measure- ments on the substances listed in Table 1. We have also obtained elemental composition data for the substances listed in Table 1.

Our heat of combustion measurements constituted the first new research that we did at the University of Alberta after moving from the University of Lethbridge in mid 1983. The apparatus (constant volume calorimeter, platinum resistance thermometer, etc.) used for these measurements was set up by Hai-Ke Yan, who was also responsible for making many of our measurements. More recently, research on heats of combustion has been continued as a collaboration between my group in Edmonton and Yan's group at the Academia Sinica in Beijing. We have calculated results of all of our measurements (from Edmonton and from Beijing) as U values for reactions represented in general by the chemical reaction equation (not balanced)

[1] (Oil, coke, etc.) + $0_2(g) = C0_2(g) + H_2O(liq) + SO_2(g) + N_2(g)$ + solid ash

Results of our measurements of heats of combustion can be summarized with useful accuracy by an equation of the form

[2] $-\Delta U^{\circ} = A(\text{wt \% C}) + B(\text{wt \% H}) + C(\text{wt \% S}) + D(\text{wt \% 0} + \text{wt \% N})$

The Edmonton and Beijing groups expect to publish all of these experimental results and our calculations with equation [2] soon.

SPECIFIC HEAT CAPACITIES

Among the parameters needed for proper design and assessment of all thermal processes are specific heat capacities of all substances to be heated or from which useful heat might be recovered. We have therefore measured many specific heat capacities over wide ranges of temperatures.

We have made specific heat capacity measurements on many samples of many substances at many temperatures and therefore have thousands of "data points." Because it is most useful to have summarizing equations, we have reported all of our results in terms of equations of the forms

[3] $C_p = a + bT + cT^2$ and $C_p = a + bT + cT^{-2}$

Substances for which we have measured specific heat capacities are listed in Table 2.

Our results (20-90°C) for several emulsions (oil field produced emulsions and our own synthetic emulsions) have shown that specific heat capacities of emulsions are additive (± 1.5%) as in

[4] $C_{p,em} = f_w C_{p,w} + f_o C_{p,o}$

in which C_p and f indicate specific heat capacities and mass fractions of components and subscripts em, w, and o indicate emulsion, water, and oil.

Our measurements on several samples of whole oil sands and on their separate components have established that specific heat capacities of whole oil sands are also additive as expressed by

[5] $C_{p,os} = f_{cs} C_{p;cs} + f_{fs} C_{p,fs} + f_b C_{p,b} + f_w C_{p,w}$

in which Czp and f indicate specific heat capacities and mass fractions of defined components and subscripts os, cs, fs, b, and w indicate whole oil sands, coarse solids (mostly silica), fine solids (mostly clays), bitumen, and water, respectively.

Results of many of our measurements of specific heat capacities have been summarized in a paper(1) published in 1985.

KINETICS AND ENERGETICS OF OXIDATION OF BITUMEN IN RELATION TO IN SITU COMBUSTION

Most previous investigations of the kinetics of the oxidation of bitumen have focused on the rates of consumption of $O_2(g)$ or the rates of temperature increase in large adiabatic systems. Both of these kinds of investigations have advantages, but there are also disadvantages. In order to get around some of these disadvantages and to obtain experimental data that might be related to both mathematical and chemical models of the low temperature oxidation process, we have developed a calorimetric method of measuring the rate of heat developed by the oxidation reactions.

Our aneroid calorimeter for these measurements was built by Zhong-liang Zhang. Zhang and Leslie Barta then developed detailed methods for calibrating the calorimeter and for obtaining the desired rates of production of heat (dQ/dt) from observed rates of change of temperature (dT/dt) in the calorimetric system. Barta has subsequently made some minor improvements in the calorimeter built by Zhang. A detailed account of the calorimeter and of a few typical results obtained on rates of oxidation of bitumen is being published(2).

A simple mathematical expression for the rate of oxidation of bitumen is

[6] $\text{Rate} = dQ/dt = k[\text{Bitumen}]^x[P(O_2)]^y$

Each series of measurements has been done with the amount and surface area of bitumen and silica held constant, which means that we are not obtaining information about such things as possible catalysis by find mineral. For our conditions, equation [6] can therefore be written as

[7] $\text{Rate} = k'[P(O_2)]^y$

On the basis of an initial assumption that y does not depend on temperature and that the temperature dependence of k' is in accord with the Arrhenius equation for a single reaction, [7] becomes

[8] $\text{Rate} = k_o[\exp(-E_2/RT)][P(O_2)]^y$

Results of our extensive series of measurements with Athabasca bitumen have shown that equation [8] does not provide an accurate representation of the dependence of the rate of oxidation on temperature and pressure; this is because the explicit dependence on temperature is more complicated than $\exp(-E_a/RT)$ and because y in equation [8] depends on the temperature. We have therefore undertaken a more elaborate mathematical analysis that is being described in detail elsewhere (3).

Results of our mathematical analysis of the rates of oxidation in combination and of chemical analyses have led us to propose a chemical model to supplement our mathematical model (3) of the oxidation process. This chemical model can be summarized briefly by the following:

[9] Bitumen + $0_2 \rightarrow$ "Oxygenated Bitumen" + Heat

[10a] Bitumen + $0_2 \rightarrow (C0_2, H_20$, etc.) + Heat

[10b] "Oxygenated Bitumen" + 02 $\rightarrow (C0_2, H_20$, etc.) + Heat

Reactions of type [9] leading to formation of "oxygenated bitumen" (also called "coke" or "fuel") are the principle class of reactions at low temperatures ($<<285^\circ$ C), while more typical combustion reactions represented by equations [10a] and [10b] are most important at high temperatures ($>>285^\circ$ C).

All of our kinetic investigations have been on dry oxidation reactions. Our plan now is to continue with similar investigations of wet oxidation in which $H_20(g)$ is mixed with the $0_2(g)$. We also intend to investigate the possible catalytic effects of the fine minerals, especially clays.

Throughout this work, our intent is to use our experimental results as the basis for mathematical and chemical models of the oxidation process, with these models ultimately bein related to in situ combustion processes.

SOLUBILITIES OF GASES IN LIQUIDS, INCLUDING BITUMEN

Solubilities of gases in liquids (solvents, diluents, light oils, heavy oils, bitumens) are important in several ways. Traditional methods of measuring solubilities of gases in very viscous liquids (such as bitumen) are difficult and have led to some controversial results. Partly because of a general interest in thermodynamics of gas-liquid system and partly because of a specific interest in gas-bitumen system, we have undertaken the following investigations.

Hai-Ke Yan took the lead in designing and building a constant pressure apparatus similar to earlier designs by Morrison and Billett and by Hayduk, Walter, and Simpson. Yan, Zhong-liang Zhang, Harbinder Singh, and Myron Roth have all subsequently used this apparatus for measurements of solubilities of several gases in water, in hexadecane, in toluene, and in toluene + bitumen solutions, at various temperatures and pressures. Results of these measurements have been used in a number of thermodynamic calculations. In addition, we have combined the results obtained for gases in toluene with the results of gases in toluene + bitumen solutions to obtain solubilities in pure bitumen.

Gas-liquid chromatography (GLC) offers the possibility of being a useful method of measuring solubilities of gases in very viscous decane was chosen for this investigation because it has low enough viscosity to permit reliable measurement by a traditional equilibrium method and also low enough vapour pressure to permit its use as a stationary phase in GLC. These measurements, which were done by Young-sang Choi and Harbinder Singh, have shown that the GLC method has several advantages for investigations of quite soluble gases or vapours, but also has important disadvantages when applied to less soluble gases. Yuming Xu is now investigating the direct application of the GLC method to solubilities of gases and vapours in bitumen.

We are presently preparing several papers that will provide full accounts of our experimental methods for measuring solubilities of gases in liquids, our experimental results, and our thermodynamic calculations with these results.

THERMODYNAMIC PROPERTIES OF AQUEOUS SOLUTIONS

We have carried out many investigations, mostly involving calorimetric measurements, of the thermodynamic properties of aqueous solutions, some of which have direct connection with problems arising in the petroleum industry. Examples of such work are provided in references (3-7).

COLLOID AND INTERFACIAL CHEMISTRY

We have carried out two general kinds of investigations in the area of colloid and interfacial chemistry. One kind has been intended to supply basic scientific knowledge to be used in our applied research and the other kind has been directed at petroleum-related problems.

Examples of our basic research in colloid and interfacial chemistry include investigations of ion exchange by clays (8), an improved method of measuring electrophoretic mobilities of colloidal particles (9), investigations of viscosities of aqueous suspensions of clays (10), and work on the thermodynamic properties of surfactant solutions (11, 12).

Examples of our research on applied colloid and interfacial chemistry are provided in accounts (13, 14) of investigations related to the oil sands tailings that result from processing mined oil sands in an account (15) of some of the properties of the produced water from an in situ oil sands pilot plant.

Other investigations (results not yet published) have involved electrophoretic measurements on various emulsions of bitumens and asphaltenes, measurements of interfacial tensions in various bitumen-water systems, measurements of contact angles, and investigations leading to a proposed treatment process for dealing with very large quantities of oil sands tailings.

TABLE 1
HEATS OF COMBUSTION AND ELEMENTAL COMPOSITIONS

☐ *Bitumens/heavy oils from Canada (Athabasca, Peace River, Cold Lake), Madagascar, Nigeria, and United States (Asphalt Ridge, Utah)*

☐ *Asphalenes and maltenes from Athabasca bitumen*

☐ *H-oil pitch from Syncrude*

☐ *Synthetic crude, produced by Syncrude from Athabasca bitumen*

☐ *Several naphthas from Syncrude*

☐ *Heavy oils from the Peoples Republic of China (Xinjiang and Liaohe)*

TABLE 2
SPECIFIC HEAT CAPACITIES

☐ *Bitumens/heavy oils from Canada (Athabasca, Cold Lake, Eyehill- Lloydminster, Primrose, Peace River, Grosmont), United States (Asphalt Ridge, Utah), Malagasy, Nigeria, Zaire, and Venezuela*

☐ *Asphaltenes from Canada (Athabasca, Cold Lake, Peace River) and Nigeria*

☐ *Coke from Syncrude and Suncor*

☐ *Reservoir minerals from Canada (Athabasca, Cold Lake, Peace River, Grosmont), United States (Asphalt Ridge, Utah), Malagasy, Nigeria, and Zaire*

☐ *Several clays and dehydrated clays*

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MEASUREMENT AND CORRELATION OF EQUILIBRIUM PROPERTIES APPLIED TO BITUMENS AND HEAVY OILS

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ABSTRACT

Multicomponent and multiphase equilibrium properties (such as gas solubilities, phase behaviour, Pressure-Volume-Temperature (PVT) relationships) of bitumen or heavy oil containing mixtures are often difficult to measure due to the complex and viscose nature of bitumens and heavy oils. Therefore, accurate data on these properties are seldom available in literature. In turn, correlations based on unreliable data, by means of empirical approach, do not and cannot give satisfactory predictions. This paper will review different measuring methods and discuss a recently proposed and more rigorous approach to correlating equilibrium relationships. This approach is different from that commonly adopted practice of matching the pseudo-binary phase equilibrium properties of gas-bitumen mixtures. It can be used for not only testing the internal consistency of, but also, predicting the phase behaviour data of bitumen/heavy oil containing systems.

INTRODUCTION

Bitumens and heavy oils represent one of the most complex non-living organic materials found in nature. The chemical composition, chemical reaction, biodegradability, physical, chemical and rheological properties of bitumens and heavy oils are very complex and may all vary considerably from one reservoir to another. Gas components often co-exist with bitumen or heavy oil in reservoirs. Equilibrium properties such as gas solubility, phase behaviour and PVT data are required in process calculations and engineering designs. However, to measure multicomponent equilibrium properties of bitumen or heavy oil containing mixtures is not an easy task due to the complex and viscose nature of bitumens and heavy oils. For this reason, data on these properties with higher accuracy are seldom available. Consequently, correlations based on unreliable data would not and cannot give satisfactory predictions.

This paper attempts to review the various measuring methods which are currently used in different laboratories. A more rigorous treatment of equilibrium data via equations of state (EOS) different from conventional approach of matching the pseudobinary phase equilibrium properties of gas- bitumen mixture will also be discussed.

EXPERIMENTAL METHODS FOR MEASURING PHASE EQUILIBRIUM

The frequently used methods for determination of vapour-liquid equilibria include the forced vapour recirculating method, the static method, the dew-point and bubble-point method and the flow method may be considered for measuring equilibrium properties of mixtures involving heavy hydrocarbons such as bitumens or heavy oils. At present, however, the circulation and the static methods at isothermal (constant temperature) conditions were mostly chosen to obtain equilibrium values for bitumen-containing system.

An experimental determination of phase equilibria involves the measurements of temperature, pressure and concentrations of both vapour and liquid phases (ie. T-P-y-x). It is necessary to separate samples of the liquid and vapour which are in equilibrium. During the sampling period, the system temperature and pressure have to be maintained unchanged, otherwise the equilibrium state will be disturbed and conditions are shifted.

In the determination of phase behaviour of bitumens or heavy oils in the presence of gases and liquids, equilibrium is reached in the static method by mechanical mixing or by rocking the mixture in an equilibrium cell which is placed in a constant temperatures bath.

Lal et al.(1) of the University of Alberta used an Autoclave Model AFP2005 with a volume of two liters as the equilibrium cell. Mixing of the fluids within the equilibrium cell was achieved by using a magnetic stirrer at a stirring rate of 600 rpm. A schematic diagram of the apparatus is shown in Figure 1. Equilibrium pressures were measured with Heise bourden tube gauges with ranges of 0-34.0 MPa and 0-6.8 MPa. The temperature of the cell was measured with an iron-Constantan thermocouple which was inserted into a thermowell extending into the liquid phase. Another thermowell was added, extending into the vapour phase to measure vapour temperatures. Temperatures were controlled with ±0.5°C. The cell was left overnight to ensure equilibrium was reached. Samples of the vapour were withdrawn from the top of the autoclave and analyzed using a Hewlett-Packard Model 5710A gas chromatograph. While samples of the liquid were withdrawn from lower portion of the cell into a weighed sample bottle. The gases which evolved from the liquid were measured volumetrically using a calibrated burette and cathetometer, and then analyzed with the gas chromatograph.

Robinson and Sim(2), also of the University of Alberta, used a stainless equilibrium cell with a maximum working volume of 200 cm^3. The bottom of the cell was attached to the piston head of a Ruska-type positive displacement pump so that the system pressure can be kept at a constant value during the withdrawal of samples. The head at the top of the cell contained a stirring device and openings for pressure measurement, charging and sampling. It was sealed by a glass-filled teflon packing. Mixing within the cell was provided by a belt driven stirrer. A diagram of the equilibrium cell is shown in Figure 2 and a schematic arrangement of the experimental apparatus is shown in Figure 3.

Fu et al.(3) at the Alberta Research Council measured vapour-liquid equilibrium (VLE) properties for systems containing bitumen by using an equilibrium cell which is shown in Figure 4. Mixing of the fluids within the equilibrium cell was achieved through the rocking action by means of a motor. A schematic arrangement of the experimental equipment is shown in Figure 5. In this design the maximum temperature tested was 423.2 K (150°C) with an accuracy of ±0.02 K and the upper pressure limit tested was 13.8 MPa with an accuracy of ±1.0 KPa. One of the unique features of the equilibrium cell is that both vapour and liquid volumes of the fluid can be measured accurately by using a piston and a visual cell as shown in Figure 4. The cell allowed multiple samples to be withdrawn from both vapour and liquid phases which were in equilibrium. A two-day period was required for the contents in the cell reaching equilibrium.

In the same laboratory at the Alberta Research Council, Fu et al.(4) also designed and constructed a vapour-circulating apparatus in order to expedite the time required reaching equilibrium. A schematic arrangement of the recirculating apparatus is shown in Figure 6. In this design, the maximum temperature of measurement was increased to 250°C. The apparatus was calibrated and commissioned by comparing the vapour-liquid equilibrium data of CO_2-Athabasca bitumen system at 100°C obtained by using both the rocking cell and the vapour recirculating apparatus. The comparison is shown in Figure 7. The good agreement indicates that the new apparatus can produce reliable phase equilibrium results. This apparatus is also capable of measuring the PVT data.

Svrcek and Mehrotra(5) at the University of Calgary determined the solubility of gases in bitumen by means of a mixing cell in which mass transfer between the gas and bitumen took place. The bitumen in the circulation line passed through the viscometer (Contraves DC44) before returning to the mixing cell. a schematic diagram of the apparatus is shown in Figure 8.

Langier and Richon(6) of France have recently designed a Micro-PVT apparatus which is suited for measuring GOR's of oil from the production well as a function of pressure. The design concept is similar to that of Robinson and Sim(2). The apparatus avoids use of mercury and works with small sample quantities up to 72,000 kPa and 200°C. The PVT cell is light enough to be weighed with an analytical balance within 0.5×10^{-5} Kg. Efficient mixing inside the PVT cell was achieved using a magnet rotating in a magnetic field. Internal volume of the PVT cell was varied by movement of a piston, the displacement of which was measured within 1 mm to give accurate volume determination. The schematic diagram and design of the PVT cell are shown in Figures 9 and 10 respectively. No data have been measured for heavy hydrocarbons by this apparatus. The suitability of the apparatus for measuring equilibrium properties of bitumen containing system remains to be seen.

Radosz(7) recently presented a continuous flow apparatus for measuring high pressure phase equilibria in systems containing supercritical gases and heavy hydrocarbons. Depending on the system, it took up to 30 minutes to reach a steady state with constant effluent stream compositions. The suitability of the apparatus for systems containing bitumen has yet to be established.

Chung et al.(8) proposed a method for measuring properties of heavy oil and CO_2 system. It consists of an equilibrium cell, circulation pump, gasmeter, and other attachments as shown in Figure 11.

The important factors for a good experimental work are relied on the design of the equilibrium apparatus, the appropriate preparation of the experiments, the adequate sampling procedures and techniques, the control of temperature and pressure, the accuracy of phase composition analyses, and the assurance of reaching equilibrium state.

PREDICTING METHODS

Various predicting methods including direct data fitting correlations and equations of state are available in the literature for PVT and equilibrium properties of bitumen and heavy oil mixtures. When a pure gas contacts bitumen at isothermal conditions and then reaches its equilibrium, one may express this condition thermodynamically by equalizing the fugacities, $\hat{f}$

$$\hat{f}_{gV} = \hat{f}_{gL} \tag{1}$$

(1)

$$\hat{f}_{bV} = \hat{f}_{bL}$$

(2)

where subscripts g and b refer to the gas and bitumen, and subscripts V and L refer to the vapour and liquid phases, respectively.

For the gas component,

$$\hat{f}_{gV} = \Phi_{gV}\, y_g P \tag{3}$$

$$\hat{f}_{gL} = \Phi_{gL}\, x_g P \tag{4}$$

and

$$\ln \Phi_{gv} = 1/RT \int_V^{\infty} ((\partial P/\partial n)_{T,V,n} - RT/V) dV - \ln Z \tag{5}$$

Equation (5) is also applicable for bitumen by replacing Φ_{gv}, with Φ_{bv}.

In Equation (5), the fugacity coefficient, Φ, is a function of volumetric properties of mixture which can be further expressed by a suitable equation of state. Cubic type of equations of state is the most popular correlation method to be used in bitumen and heavy oil mixtures. A general expression for the cubic equations of state can be expressed in the form of an extended van der Waals[9] (VDW) equation of state,

$$P= (RT/(V-b)) - (a/(V^2 + ubV + wb^2) \tag{6}$$

The original V^2 in the denominator of the VDW equation was replaced by the expression $(V^2 + ubV + wb^2)$. Equation 1 reduces to the original VDW equation with u=w=0; to the Peng-Robinson(10) (PR) equation with u=2 and w=-1, to the Redlich-Kwong(11) (RK) equation with u=1 and w=0, and to Soave form(12) of the RK equation with a=a(T). a number of other cubic equations of state can be obtained when certain particular values of u and w in Equation (1) are assigned. The parameter a of equation are expressed in term of critical temperature and critical pressure by means of

$$a = \Omega_a R^2 T_c^2 / P_c \tag{7}$$

with Ωa treated temperature dependent and its coefficient generalized in term of Pitzer's acentric factor, w. The parameter b is defined as

$$b = \Omega_b R T_c / P_c \tag{8}$$

In VLE calculations involving heavy oil and bitumen, the following conventional mixing rules are often employed for these cubic equations of state:

$$a= \sum\sum x_i\, x_j\, a_{ij} \tag{9}$$

$$b = \sum b_i\, x_i \tag{10}$$

Among these cubic equations of state, the PR and the modified Soave-Redlich- Kwong(13-15) (SRK) equations of state are most frequently applied in the bitumen and heavy oils containing systems.

Hence, parameters a and b refer to phase composition of the mixture. Although Equations (9) and (10) are expressed in term of the mole fractions of component i and j in the liquid phase, they can be also applied to the vapour phase composition by replacing x with y. The cross coefficient aij is frequently expressed by

$$a_{ij} = (a_{ii}\, a_{jj})^{0.5}\,(1 - k_{ij}) \tag{11}$$

The quantity k_{ij} is called the binary interaction coefficient which is determined by binary data. In VLE calculations, $k_{ij} = k_{ji}$ and $k_{ii} = k_{jj} = 0$ are assumed.

In the application of an equation of state in the VLE calculations., such as predicting gas solubilities in bitumen or heavy oil, it is apparent that characterization parameters, are required as input for each ingredient of the mixture. These parameters, which are critical temperature, T_c; critical pressure, P_c; critical volume, V_c; and acentric factor, w, have been reported in the literature for most light hydrocarbons. The characterization parameters for bitumen or heavy oil can not be experimentally determined due to the high boiling point and complex molecular structure of the bitumen and therefore these parameters must be determined by various estimation methods. Some of these are highly dependent upon the choice of the EOS, the method of regression, the techniques of extrapolation or the quality of experimental data. Several sets of these characterization parameters, which had been used earlier and reported in the literatures, are listed as referred as "Old Set" in Table 1. The old set of characterization parameters, as obtained from the fitting the binary VLE properties, failed to correlate the liquid density data with cubic equation of state as depicted in Figure 12. The accuracy of predicted values can be greatly improved when an appropriate set of binary interaction coefficient values(16,17) are used in VLE calculations by means of those equations of state. However, binary interaction coefficient values has less impact on correlating the liquid density data.

It was found by Fu et al.(18) that deviations in the liquid densities of a mixture can be greatly influenced by changing the critical temperature and critical pressure, but not so strongly influenced by changing the value of the binary interaction coefficient for each of the three gas-bitumen systems. Also, the effect on the calculated results of changing the acentric factor is moderate in comparison to the other parameters, T_c and P_c, for all the systems studied. Thus, the prediction of the liquid density of a mixture using the PR or the MSRK equation of state cannot be greatly improved by varying only the acentric factor of bitumen and/or the binary interaction coefficients of the mixture (even up to 50%), but these parameters will affect the results of equilibrium calculations, especially the acentric factor.

It is desirable to determine the characterization parameters for bitumens and heavy oils by a different method that is independent of the equation of state and regression techniques. These independently-determined characterization parameters should be applicable to all equations of state for representing the "pure" bitumen if the experimental data are consistent. It is therefore possible to test the internal consistency of the volumetric and phase equilibrium data with a unique set of characterization parameters. Both liquid densities and phase equilibrium data could be satisfactorily represented by an equation of state with a single set of pure-component characterization parameters.

Using the above-mentioned concept, we searched the literature to determine a suitable correlation to predict critical properties for bitumen based on the compositional analyses of bitumen. The proposed method and resulting critical parameters for Alberta bitumens and heavy oils are reported by Fu et al.(19) These sets of characterization parameters referred as the "New Set" are also reported in Table 1. With these characterization parameters, and in association with either the PR or the MSRK equation, we were able to predict both phase equilibrium data and liquid densities of gas-bitumen mixtures. The calculated results were analyzed and compared with those obtained with the old set of characterization parameters using both equations of state.

An attempt was also made to investigate the differences of the predicted liquid phase densities between the new set and the old set of the characterization parameters with two equations of state. As an example shown in Figure 13, the predicted liquid phase densities of carbon dioxide-Athabasca bitumen mixture both by the PR and the MSRK equations of state with new set of Characterization parameters of Athabasca bitumen, T_c=963.7 K, P_c=1.133 MPa, and w=1.274, have greatly improved from those calculated with the old set of parameters, T_c=911.48 K, P_c=0.692 MPa, w=1.659. In addition, the predictions of VLE properties for same system by both equations of state are well agreed with measured data as shown in Figure 14. This implies that the new set of parameters are applicable to both equations of state (maybe all equations of state) in VLE calculations.

Recently, Yu et al.(20) proposed a three parameter cubic equation of state which can improve in the calculation of liquid volume of bitumen and heavy oil. Yu and Lu(21) have also proposed a volume translation technique to change from a two-parameter cubic equation to a three-parameter equation such as applied in the PR equation without affect its Ω_a value at critical point. It was reported that such translation can improve the liquid volume prediction for heavy hydrocarbon systems such as CO_2-C_{19} and C_1-C_{10}.

CONSISTENCY TEST FOR GAS SOLUBILITY DATA

In general, an equation of state is always prefer to use than a rough and simple data fitting correlation which although is easy to use. The reason is the equation can not only predict the required properties with high accuracy but also provided the internal consistant test for the data. Recently, Lu et al(16) provided a data treatment method with Krichevsky-Kasarnovsky(22) equation which can test the PVT and equilibrium data of the bitumen and heavy oil mixtures with high accuracy. The equation,

$$\ln(\hat{f}_2/x_2) = \ln K_H + (\bar{V}_2\,(P - p_1))/RT \quad (12)$$

is suitable for representing solubilities of slightly soluble gases up to high pressures. In other words, when solubilities are very low, it is expected that a linear relationship be observed on the plot of a $\ln(\hat{f}_2/x_2)$ versus P. The quantities $\hat{f}_2$, $\bar{V}_2$, and x_2 refer to the fugacity, partial molar volume, and mole fraction of the dissolved gas in bitumen or heavy oil, respectively. The quantity P is the system equilibrium pressure and K_H is the Henry's constant at the saturation pressure of bitumen or heavy oil p_1. Subscripts 1 and 2 refer to the solvent (bitumen or heavy oil) and the solute gas, respectively. Since swelling is observed when gas is dissolved in bitumen, $\bar{V}_2$ is always to be positive. Thus, on a semilogarithmic plot of the ratio $\hat{f}_2/x_2$ against P at a constant T, a smooth curve with a positive slope is expected. For small values of x_2 or P, a linear relationship should be expected.

In VLE calculation for pure gases, fugacity of pure gases may be used in stead of $\hat{f}_2$, because the concentration of bitumen is extremely small in the vapour phase. When the scattering of the data points is observed, it is an indication that some of the solubility values are of doubtful quality.

DISCUSSION AND CONCLUSION

Different measuring methods for bitumen and heavy oils properties have been reviewed. It is very interesting to note from Figure 14 that data measured in different laboratories and different apparatuses in same laboratory can be very consistant provided that those important factors for a good experimental work as discussed earlier were ensured. It also implies strongly that physical properties of bitumen-containing systems can be reproduced without any problems.

It is a well-known fact that measurements on bitumen-containing systems are tedious, time consuming and costly, and that required accurate data on these properties are seldom available in the literature. For data reduction purpose, predicting methods based on limited measured data are necessary to be developed. A more rigorous method proposed by Fu et al(19), which is different from that commonly adopted practice of matching the pseudo-binary phase equilibrium data of gas-bitumen systems, can be employed to predicting equilibrium properties for process design and reservoir simulations. This method can also be used for not only providing liquid density data of the system at the same conditions, but also for testing the internal consistency of the phase equilibrium data on bitumen/heavy oil systems.

The method of determining characterization parameters for bitumens and heavy oils as proposed by Fu et al.(19) is capable of relating the parameters to the bitumen composition. It was shown that with these new parameters, both equations of state predict reliable VLE compositions and liquid phase densities. It is believed that the confidence in the characterization parameters can be further improved if the chemical structure and molecular weight for the heavier and more complex bitumen components are better determined.

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NOMENCLATURE

a,b = coefficients of the equation of state

C_{ij} = binary interaction coefficient for components i and j

f = fugacity

K = degrees Kelvin

n = component

P = pressure

R = gas constant

T = absolute temperature

V = molar volume

x = mole fraction in the liquid phase

y = mole fraction in the vapour phase

Z = compressibility factor

z = mole fraction of component either in the liquid phase or in the vapour phase

Greek Letters

Ω_a,Ω_b = parameters of the Redlich-Kwong equation
Φ = fugacity coefficient
Δ = difference
Σ = summation
ω = acentric factor

Subscripts

av = average value
b = bitumen
c = critical property
cal = calculated
exp = experimental
g = gas
i,j = component identification
L = liquid phase
r = reduced property
v = vapour phase
1,2 = component identification
12 = mixture identification

Abbreviations

EOS = equation of state
Frac = fraction
MSRK = modified Soave-Redlich-Kwong
MW = molecular weight
No = number of components
PR = Peng-Robinson
RK = Redlich-Kwong
SRK = Soave-Redlich-Kwong
VDW = van der Waals
VLE = vapour-liquid equilibrium

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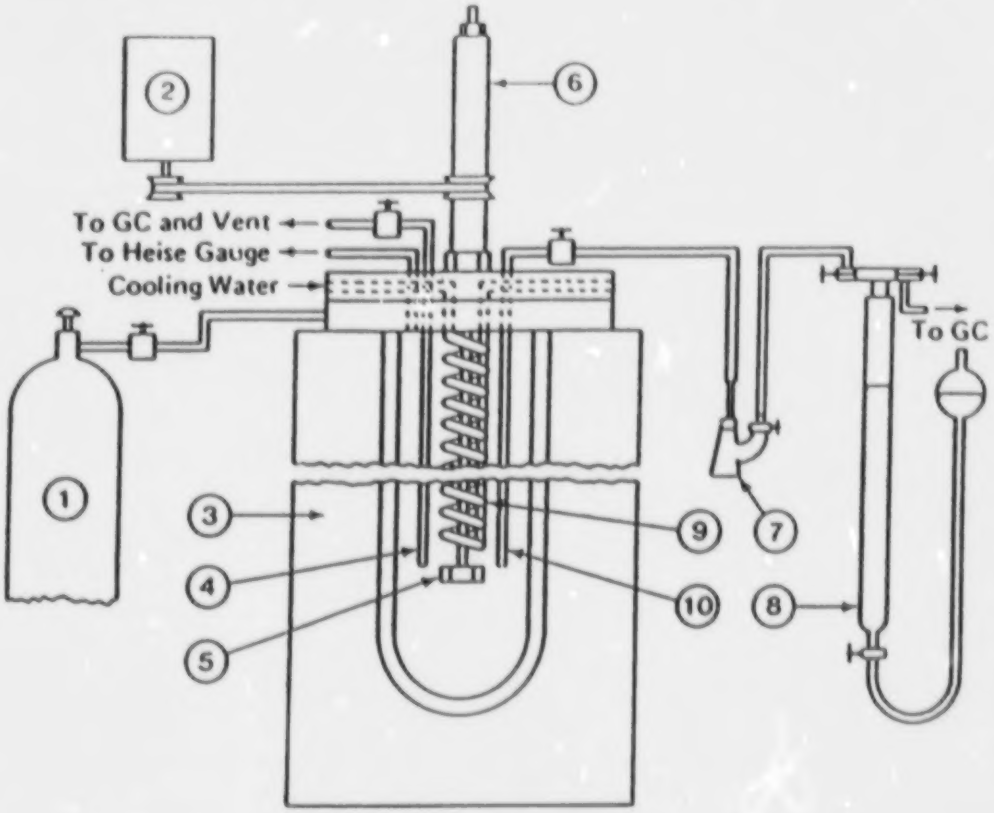
Table 1
Pseudo-Critical Properties of Bitumen

Bitumen	Set	T_c(K)	P_c(atm)	MW	ω	Reference
Critical Properties* of Bitumen from Literature (Old Set)						
Athabasca	I	963.71	11.18	533	1.274	Fu(1985)
	II	893.00	7.60	522	1.4856	Lal(1985)
	III	810.00	9.50	544	1.080	Lu(1985)
	IV	824.00	12.50	544	1.231	Lu(1985)
	V	893.00	7.60	544	1.485	Lu(1985)
	VI	930.00	14.83	544	0.792	Lu(1985)
Estimated Critical Parameters by Fu et al[19] (New Set)						
Athabasca	(C)	963.71	11.18	544	1.2740	Fu(1986)
Cold Lake	(E)	945.03	10.86	533	1.1880	Fu(1986)
Peace River	(F)	942.32	11.95	528	1.5323	Fu(1986)

* Parameters in the "EQUI-PHASE" PR package are proprietary.

Figure 1
Schematic Diagram of the Bitumen Saturation Apparatus


2
6
To GC and Vent
To Heise Gauge
Cooling Water
To GC
1
3
9
7
4
10
8
5

1 Gas cylinder
2 Stirrer motor
3 Heating jacket
4 Thermocouple well
5 Stirrer

6 Magnedrive
7 Liquid sample flask
8 Calibrated buret
9 Cooling coil
10 Liquid sample line

Figure 2
Detail of Experimental Equilibrium Cell

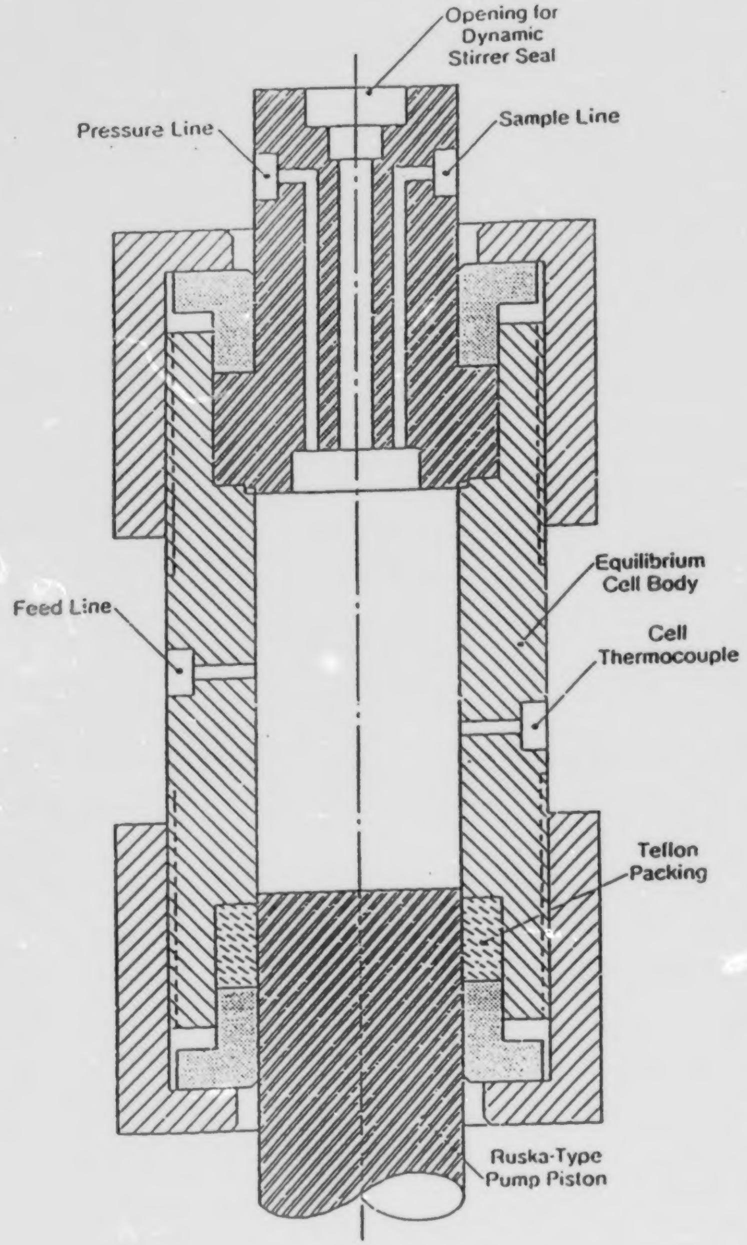
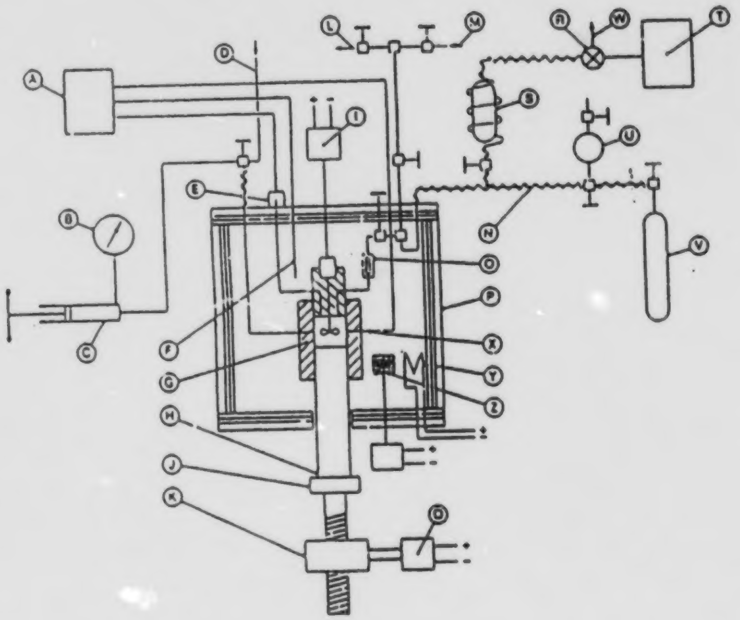

Opening for Dynamic Stirrer Seal
Pressure Line
Sample Line
Equilibrium Cell Body
Feed Line
Cell Thermocouple
Teflon Packing
Ruska-Type Pump Piston

Figure 3
Schematic Arrangement of Experimental Equipment



A. Hewlett Packard Model 3455A Digital Voltmeter
B. Heise Gauge
C. Positive Displacement Gas Pump
D. Water Injection
E. Pressure Transducer
F. Thermocouple
G. Stainless Steel Cell Body
H. Full Diameter Piston
I. Stirrer Motor
J. Temperature Break
K. Gear Box and Counter
L. Vacuum
M. Helium
N. Heat Traced Lines
O. Sapphire Windowed Observation Cell
P. Insulated Housing: Fir Plywood, Cotronics Board, Cotronics Blanket
Q. Piston Drive Motor
R. Chromatographic Valve
S. Heated Separator
T. Hewlett Packard Model 5880 Chromatograph
U. Liquid Sample Bomb
V. Gas Sample Bomb
W. Vent
X. Cell Thermocouple
Y. Electric Heater
Z. Squirrel Cage Fan

Figure 4
Vapour-Liquid Equilibrium Cell

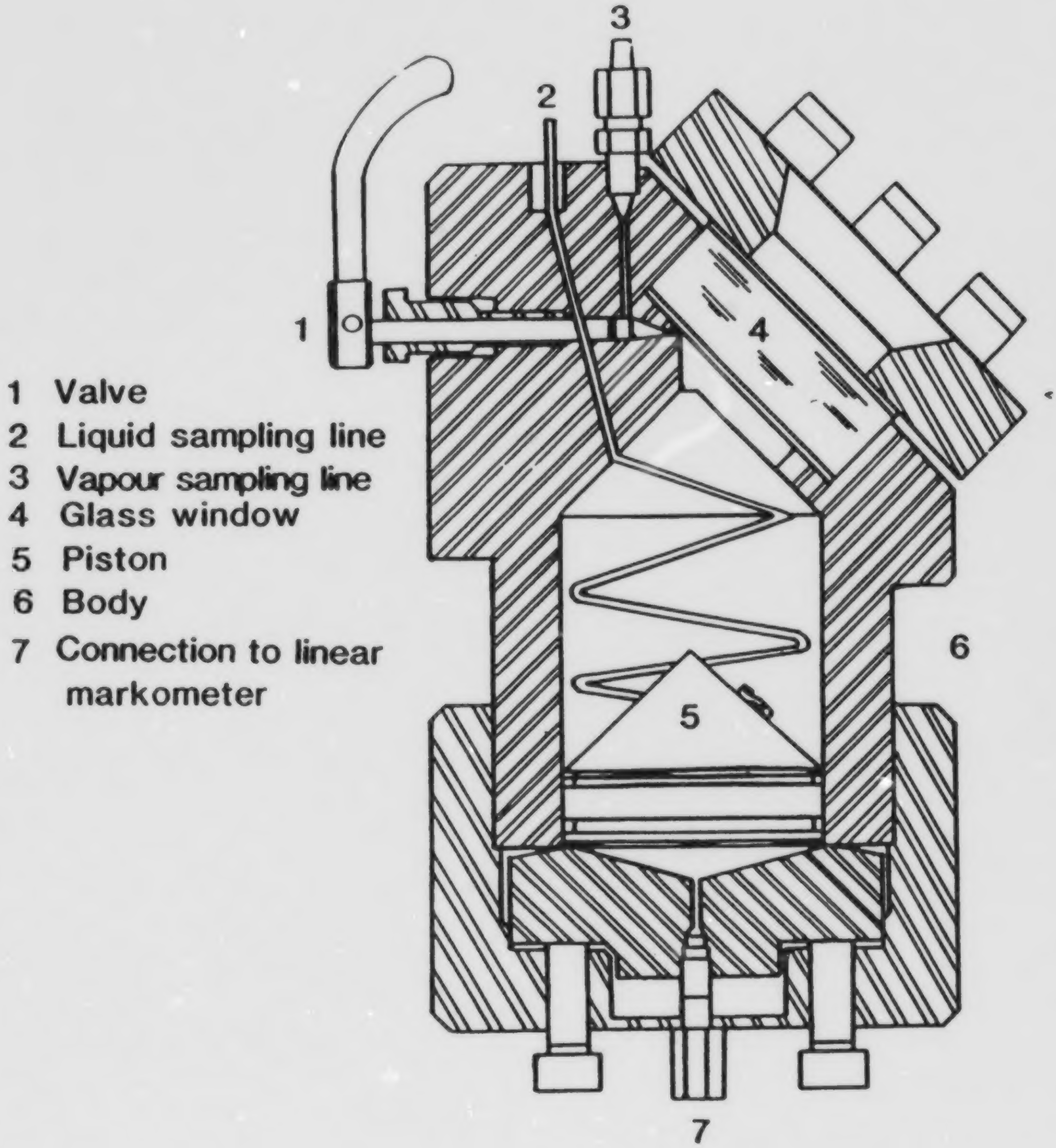
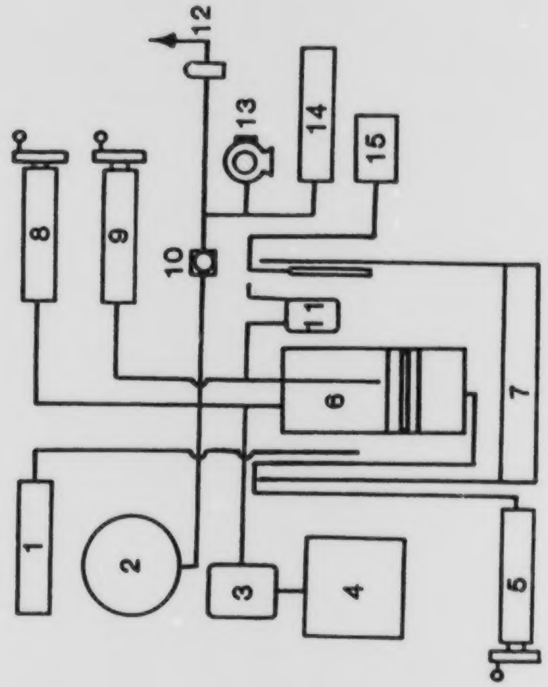

1 Valve
2 Liquid sampling line
3 Vapour sampling line
4 Glass window
5 Piston
6 Body
7 Connection to linear markometer
1
2
3
4
5
6
7

Figure 5
Schematic Arrangement of VLE Apparatus



1 HP Quartz Thermometer
2 16" Heise Pressure Gauge
3 Pressure Indicator
4 HP Data Logger
5 Ruska Pump
6 Equilibrium Cell
7 Primary Heater Control
8 Ruska Gas Pump
9 Ruska Liquid Pump
10 Sight Glass
11 Liquid Sample Cylinder
12 Relief Valve
13 Vacuum Pump
14 Purge Container
15 Secondary Heater Control

Figure 6
Schematic Flow Diagram of VLE Apparatus

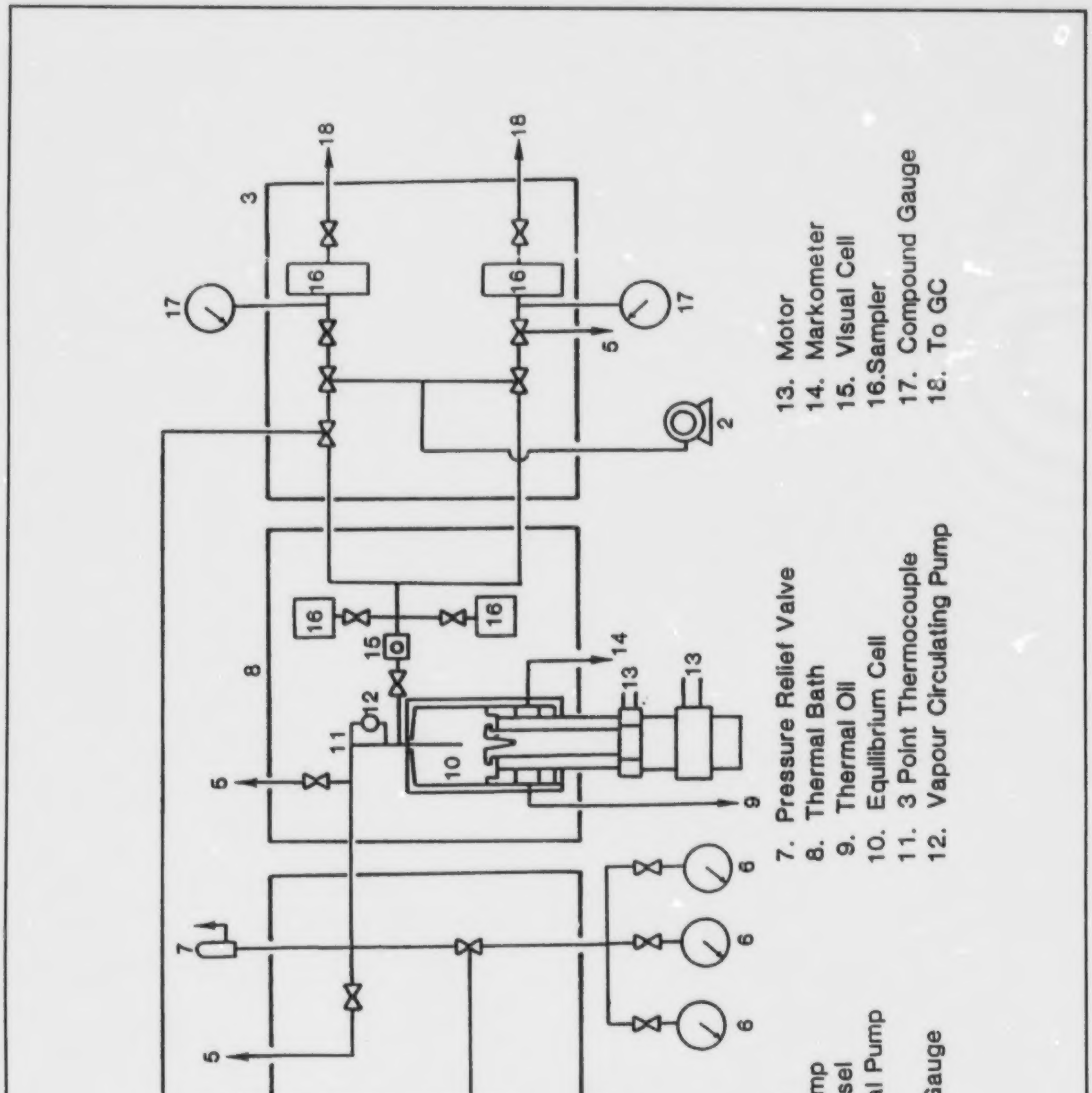

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
1. Gas Suppy
2. Vacuum Pump
3. Water Vessel
4. Proportional Pump
5. Vent
6. Pressure Gauge
7. Pressure Relief Valve
8. Thermal Bath
9. Thermal Oil
10. Equilibrium Cell
11. 3 Point Thermocouple
12. Vapour Circulating Pump
13. Motor
14. Markometer
15. Visual Cell
16.Sampler
17. Compound Gauge
18. To GC

Figure 7
Solubility of Carbon Dioxide in Athabasca Bitumen at 373 K

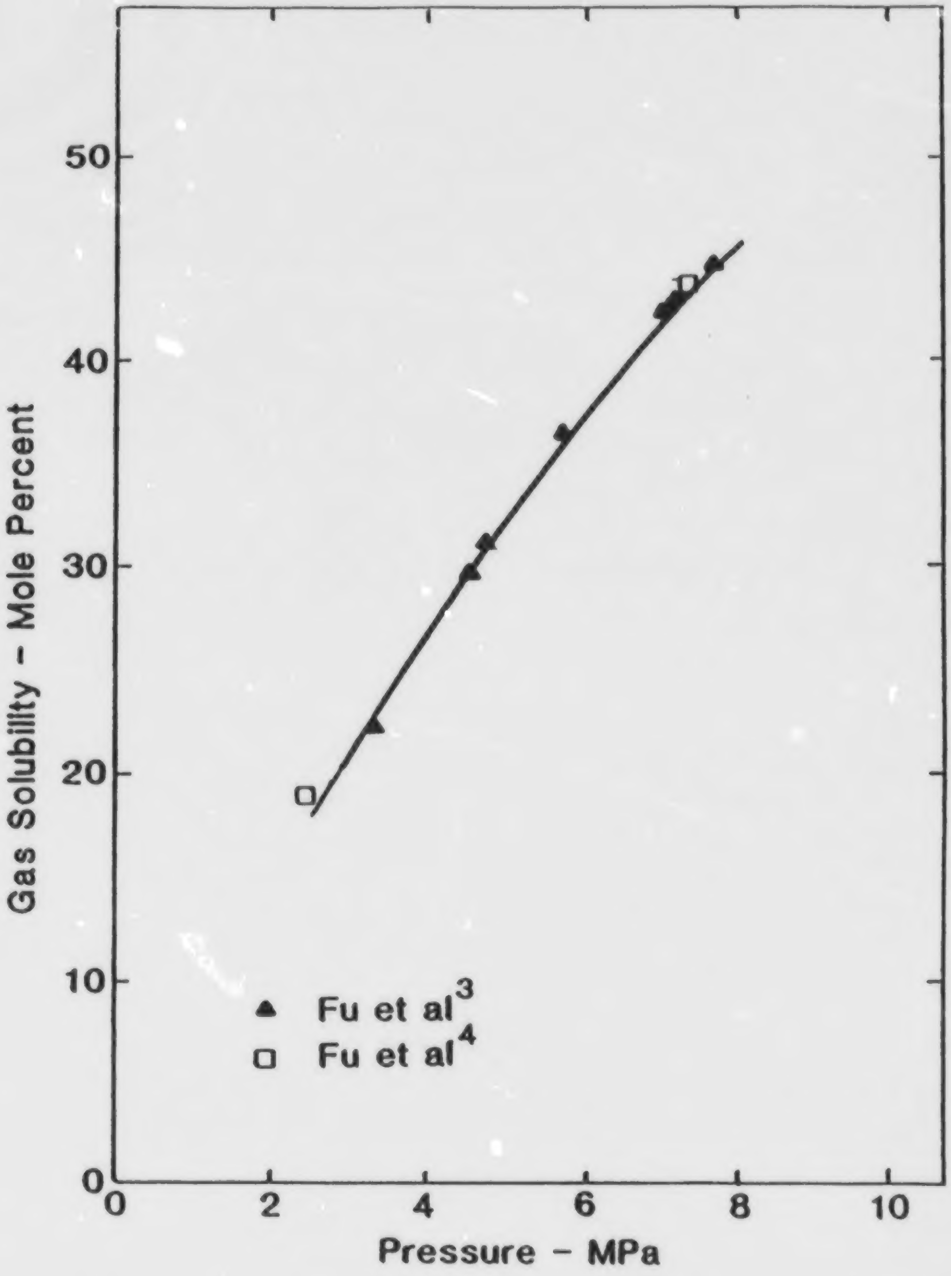


Figure 8
Schematic Diagram of Bitumen Saturation Apparatus

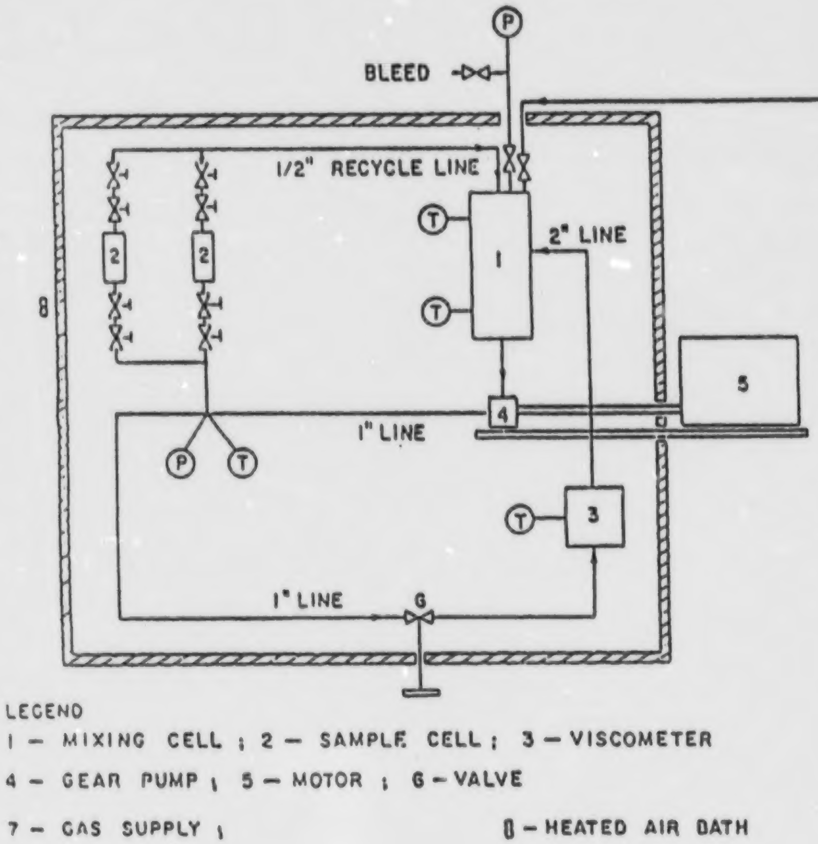
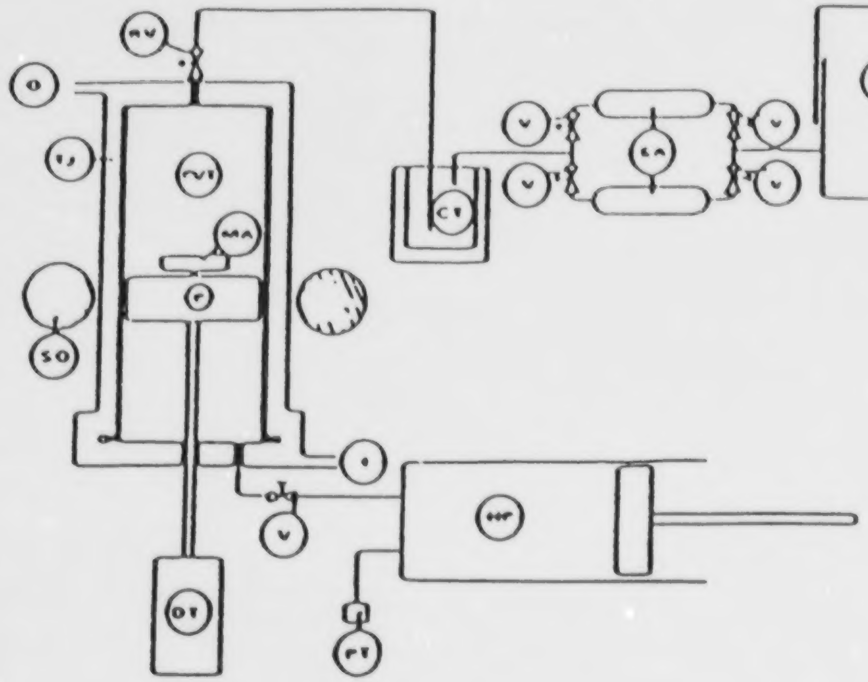
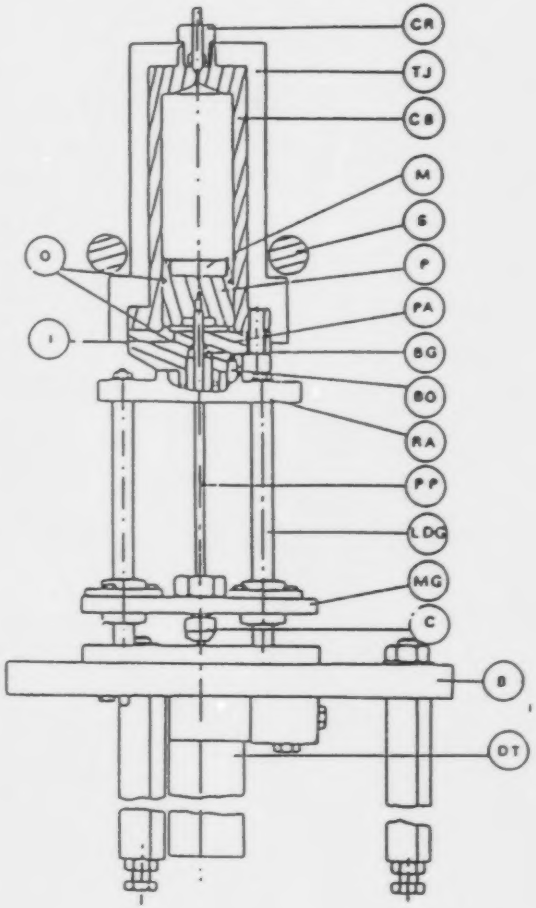

P
BLEED
1/2" RECYCLE LINE
T
2" LINE
1
T
2
2
8
7
5
4
1" LINE
P
T
T
3
1" LINE
6
LEGEND
1 – MIXING CELL ; 2 – SAMPLE CELL ; 3 – VISCOMETER
4 – GEAR PUMP ; 5 – MOTOR ; 6 – VALVE
7 – GAS SUPPLY ; 8 – HEATED AIR BATH

Figure 9
Flow Diagram of the PVT Equipment



CT = cold trap
DT = displacement transducer
G = gasometer
HP = electronic hydraulic press
I = thermal liquid inlet
MA = magnet
O = thermal liquid outlet
P = piston
PT = pressure transducer
PVT = P.V.T. cell
RV = regulating valve
SA = sampling assembly
SO = solenoids
TJ = thermostatted jacket
V = shut-off valves (Autoclave Engineers)

Figure 10
PVT Cell



B = bearer
BO = bolts
BG = bronze gasket
C = connection of probe, PP, to displacement transducer
CB = cell body
CR = connection to regulating valve
DT = displacement transducer
I = pressurizing liquid inlet
LDG = linear displacement guide
M = magnetic rod
MG = movable guide
O = polymer O-ring
P = piston
PA = pressurizing assembly
PP = probe for piston level measurements
RA = rigid assembly to connect the displacement transducer
S = solenoids
TJ = thermostatted jacket

Figure 11
Experimental Apparatus

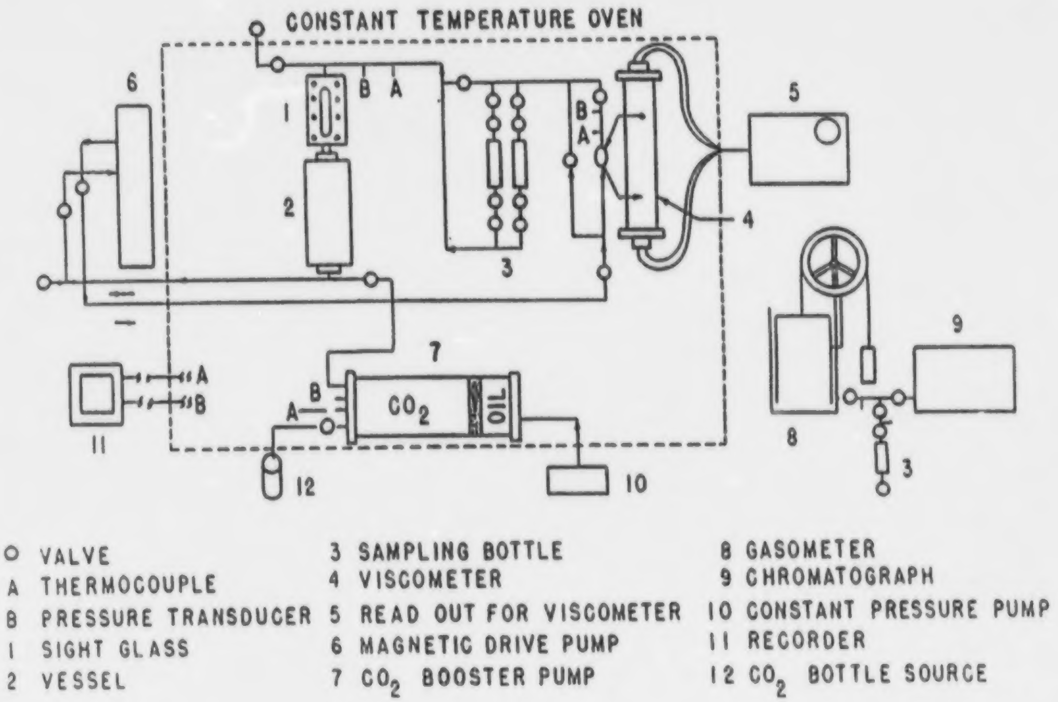

CONSTANT TEMPERATURE OVEN
6
1
B
A
2
3
B
A
5
4
7
CO_2
OIL
B
A
11
A
B
12
10
9
8
3
○ VALVE
A THERMOCOUPLE
B PRESSURE TRANSDUCER
1 SIGHT GLASS
2 VESSEL
3 SAMPLING BOTTLE
4 VISCOMETER
5 READ OUT FOR VISCOMETER
6 MAGNETIC DRIVE PUMP
7 CO_2 BOOSTER PUMP
8 GASOMETER
9 CHROMATOGRAPH
10 CONSTANT PRESSURE PUMP
11 RECORDER
12 CO_2 BOTTLE SOURCE

Figure 12
Comparison of Measured and Predicted Liquid Densities for Carbon Dioxide-Athabasca Bitumen Mixtures at 373.15 K

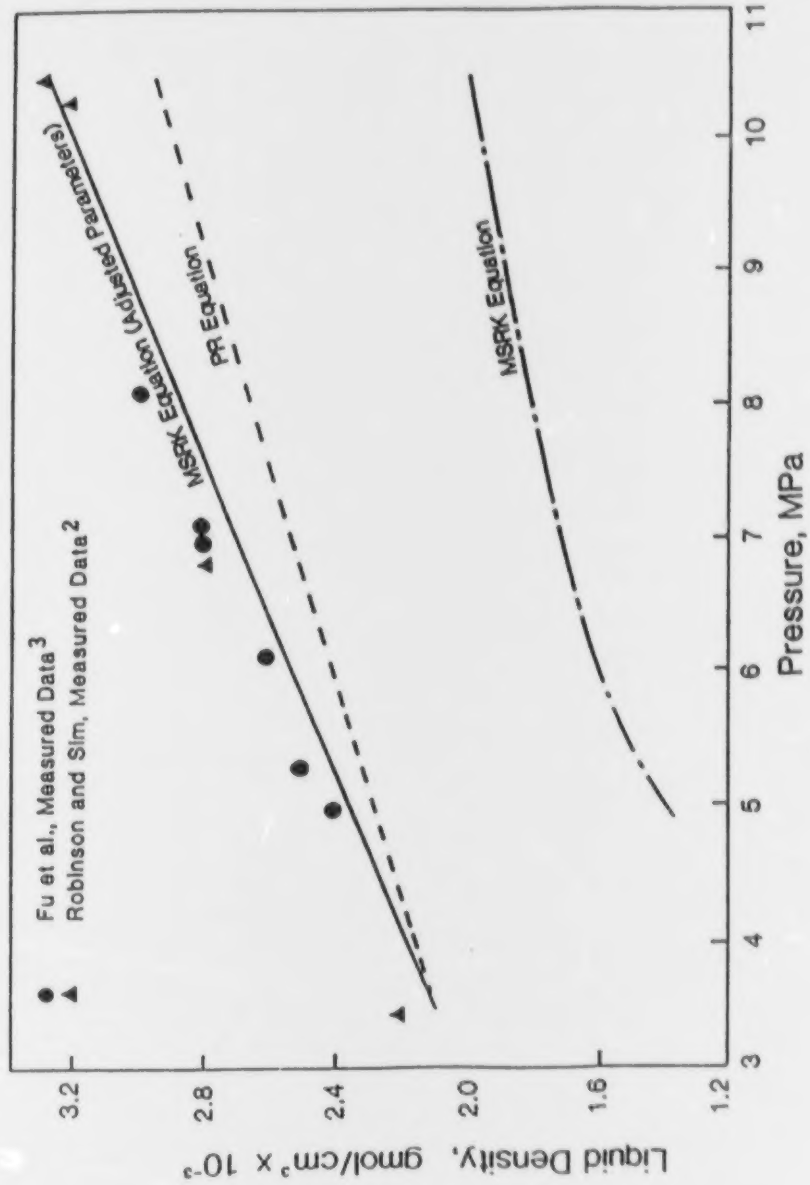


Figure 13
Comparison of Measured and Predicted Liquid Densities for Carbon Dioxide-Athabasca Bitumen Mixtures at 373.15 K

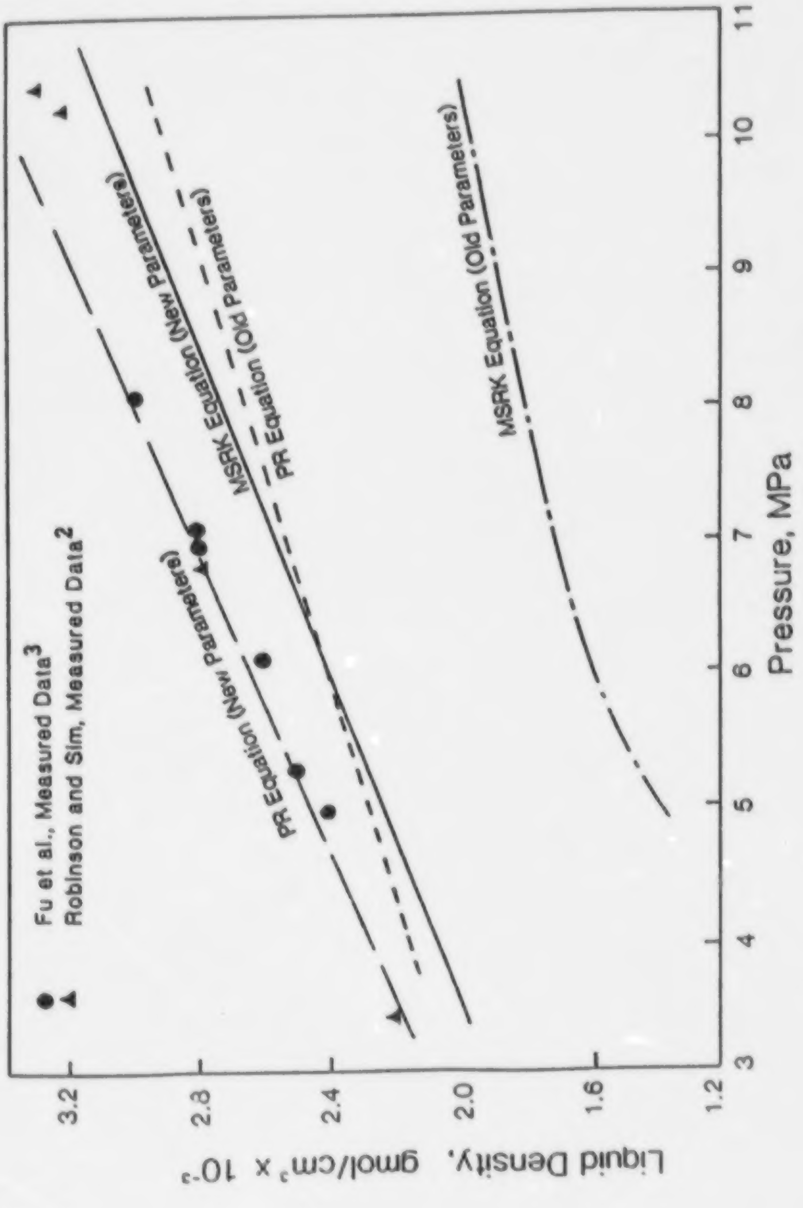
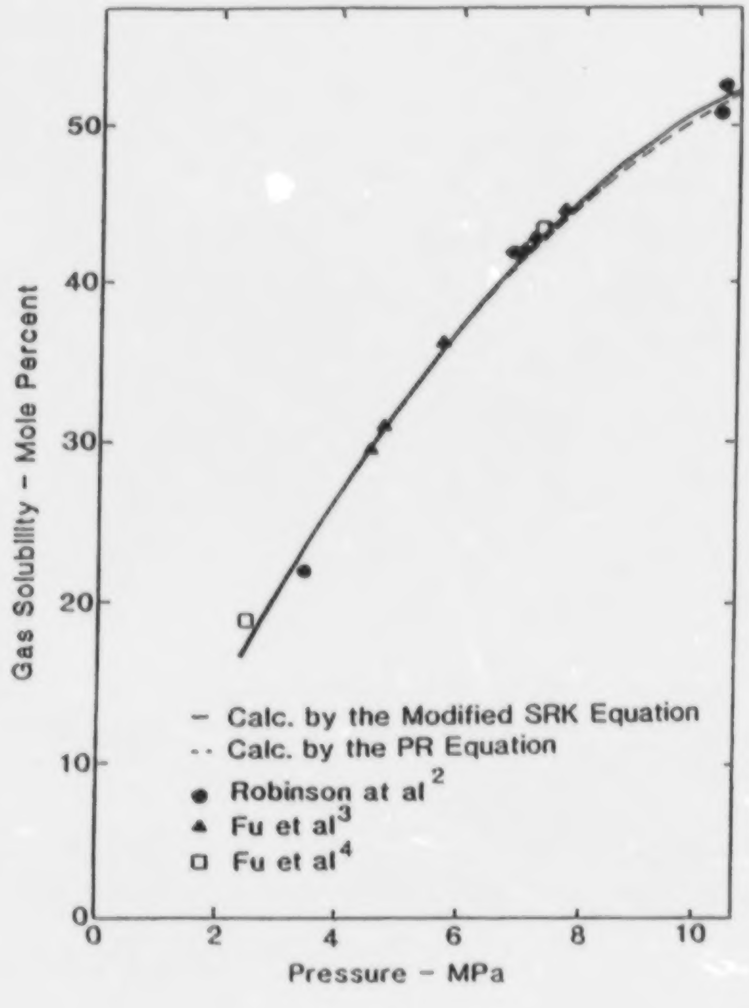


Figure 14
Solubility of Carbon Dioxide in Athabasca Bitumen at 373 K



19

USE OF FOAM FORMING SURFACTANTS TO ENHANCE THE RECOVERY OF HEAVY OILS

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Li Jian[2]
Kirk Green[1,]
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ABSTRACT

Laboratory studies were conducted using heavy oil samples from Canada (Clearwater) and China (Karamay) to examine the efficacy of two commercial foam forming surfactants as additives to steam-based processes. Foam generation experiments performed in a $1.2\ \mu m^2$ sandpack at $180^{\circ}C$ demonstrated that the presence of residual oil can have a destabilizing effect on foam bubbles preventing the generation of the foam. Interfacial tension measurements were carried out as a function of temperature (25 to $200^{\circ}C$) and salinity (0 to 20 g/L NaCl) and using Karamay field water. Since the extent of oil desaturation is dependent on interfacial tension, the data could be used to assess the ability of the surfactants to reduce oil saturations in the swept zone prior to foam formation. Studies of surfactant partitioning in static autoclaves using a 1:1 ratio of oil and water, showed that surfactant loss into the oil phase is a strong function of the surfactant type. In core- size displacement experiments, reduction of steam mobility by foam formation resulted in a substantial enhancement in oil recovery.

INTRODUCTION

Steam injection is the most widely used method to recover heavy oil from underground deposits worldwide. High amounts of residual oil, channelling and gravity segregation effects can considerably reduce the amount of oil potentially recoverable by this process. Adding surfactant to the injected steam with or without non-condensible gas is one technique used to improve the recovery efficiency of steam based processes. Surfactants can improve oil recovery by reducing the residual saturations in the hot condensate zone of the reservoir, and stabilizing the formation of a foam with either steam or preferably, a non-condensible gas phase. The foam acts to divert the steam from the swept zone. The beneficial use of foams in the field has been reported mainly for reservoirs in California and Venezuela. Field application together with the underlying phenomenon and laboratory work have been recently reviewed(1).

A major concern with foam processes is the potentially detrimental effect of residual oil in the swept zone on foam formation. In an early study, Holm(2) observed that the effect of oil on foam was to decrease gas saturation and lower the capability of the foam to trap gas. Friedmann and Jensen(3) showed that the presence of refined oil (24% residual oil saturation) had a detrimental effect on both foam generation and the propagation of a preformed foam. An additional concern with the presence of residual oil is surfactant losses due to partitioning into the oil. Al-Khafaji et al.(4) showed that for thermally stable surfactants, surfactant absorption by the oil phase was much more severe than adsorption on the sand matrix at elevated temperatures.

This laboratory study was conducted using heavy crude oil and core samples from China (Karamay) and Alberta (Clearwater). Two commercial foam forming surfactants were also selected for this study. In order to characterize and compare the two crudes, the interfacial properties, including electrophoretic mobility-pH and interfacial tension-temperature and -salinity, were determined. The interfacial tension study provided a means of assessing the ability of the surfactants to reduce oil saturation in the swept zone prior to foam formation. Partitioning studies were carried out in static autoclaves to determine the influence of the crude oil and surfactant type on surfactant losses into the oil. Flow experiments were conducted in 1.2 μm^2 sandpack to determine the effect of residual crude oil on foam formation. Displacement experiments using Clearwater and Karamay cores were conducted to determine oil recovery using foam injection to reduce steam mobility in a high permeability channel formed along the axis of the cores. The results of these investigations are reported and discussed.

EXPERIMENTAL

Samples of dewatered crude oils were obtained from the Clearwater formation in Cold Lake, Alberta and Karamay formation in Xing-Jiang, China. A summary of the physical and chemical properties of the crude oils, including chemical composition, density-temperature and viscosity-temperature relationships is given in Table 1. Sand packs were prepared from -200 mesh silica sand giving an absolute permeability of about 1.2 μm^2. The two Clearwater oil sand cores used in the displacement experiments were prepared by recombining slabbed field cores. A preserved field core was obtained from the Karamay field. SunTech IV (alkyl aryl sulfonate) and Chaser SD1000 (sulfonate dimer) were obtained from Sun Refining and Chevron Chemicals respectively. Unless stated otherwise, a 5g/L active concentration of surfactant was used as a dispersion in de-ionized water, deuterium oxide (heavy water, D_2O), Karamay produced water or NaCl brine in all experiments. The chemical analysis for Karamay produced water is given in Table 2.

Electrophoretic mobility data for the Clearwater and Karamay Crudes were determined using a Rank Brothers apparatus at 30°C as described previously by Takamura et al.(5).

Crude oil/aqueous interfacial tensions were measured using a spinning drop tensiometer equipped with temperature control up to 200°C. In order to increase the density difference between the phases, D_2O was used for the aqueous preparations except in measurements involving Karamay formation water. Details of the techniques used have been published elsewhere(6). Partitioning experiments were carried out in glass jars (75°C) and stainless steel autoclaves (125°C) using an aqueous:oil ratio of 30 g:30 g. Even with moderate agitation of the samples, emulsification of the oil was observed to occur and this interfered with the analytical technique used to determine surfactant concentration. Thus, for the runs reported no agitation or infrequent slight agitation was used. The lack of agitation resulted in incomplete equilibration and the data is interpreted in this context. The containers were sampled by withdrawing the aqueous phase at the experimental temperatures. The surfactant concentration in the aqueous phase was determined by the two-phase titration method(7) with a repeatability of ±5%. The method is open to interference from small amounts of emulsified oil which may have contributed to additional error.

A schematic diagram of the apparatus used for the foam formation tests in the presence of residual oil is shown in Figure 1. The jacketed cell (2.5 cm ID and 59 cm long) was dry- packed with sand then saturated with CO_2 gas prior to the injection of water (degassed by bubbling with helium gas). The absolute permeability of the pack was determined prior to flooding with 1.5 PV of crude oil. The crude was displaced by hot water, hot water-surfactant-gas or steam (backpressure of 0.7 MPa). The average residual saturation in the core was estimated from analysis of the produced fluids. Pressure drops were measured in three locations along the core and temperatures of the core and the injected fluids were maintained at 180°C in all experiments. At the end of an experiment, toluene followed by isopropyl alcohol was used to remove residual oil from the cell. The same pack was used for all experiments by flushing with copious amounts of distilled water, evacuating the pack to dryness, followed by flushing with CO_2 gas prior to resaturation with water. Because of the relatively high solubility of CO_2 in water at room temperature, this method was effective in displacing interstitial air. Additional details of the equipment used were published elsewhere(8).

The apparatus used and the experimental procedure for the bitumen displacement experiments was described in detail elsewhere(9,10). The cores contained an initially oil-free high permeability (about 50 μm^2) flow channel along their axis.

RESULTS AND DISCUSSION

Comparison of the Interfacial Properties of the Crude Oils

Table 1 shows that there is a considerable difference in the chemical composition of the two crude oils. The clearwater sample, for example, has a much higher asphaltene content (17% compared to 2%) but a lower acid # (1.4 compared to 5) than the Karamay sample. The electrophoretic mobility data for the two oils as a function of pH, measured at constant ionic strength of 10^{-2} M, also show a major difference. The data plotted in Figure 2 indicates that the mobility for the

Karamay crude changes from negative to positive below a pH of about 5 while the Clearwater sample is negative at all pH values. Buckley et al(11) have shown that the electronegative and electropositive character of the crude oils is likely associated with the presence of carboxylic and amine functional groups at the oil/water interface. These moieties are active over different pH ranges. Based on the results of Figure 2, it is very likely that the Clearwater sample is deficient in amine-type moieties. It has not been established what effect the electrochemistry at the oil/water interface has on interfacial tension, surfactant absorption and foam stability.

Interfacial Tension Behaviour

The results of interfacial tension measurements for Clearwater and Karamay crudes in D_2O containing SunTech IV and in D_2O containing Chaser SD1000 as a function of temperature (25 - 200°C), are plotted in Figures 3 and 4 respectively. In aqueous SunTech IV the interfacial tension values for the two oils are very similar, increasing with temperature before reaching a plateau at values above 2 mN/m. In aqueous Chaser SD1000, the interfacial tension values for the two oils above 50°C are greater than 2 mN/m and do not change with temperature. Below 50°C, the interfacial tension of the Karamay crude showed marked temperature dependence. Values of interfacial tension in the absence of surfactant are in the range of 7-10 mN/m for both oils. Thus, at elevated temperatures and in the absence of brine, the two surfactants fail to reduce interfacial tensions to values which will substantially increase capillary number and cause a reduction in residual saturation(12). This was confirmed in sand pack displacement experiments (see below).

The effect of NaCl concentration on oil/water interfacial tension for the two oils in the presence of the two surfactants at 150°C is shown in Figure 5. Both oils show similar behaviour with reductions of about one and two orders of magnitude for Chaser SD1000 and SunTech IV respectively. It was shown previously(6) that for the bitumen/aqueous sulfonate surfactant system, low interfacial tension (<0.1 mN/m) was achieved only in the presence of added electrolyte. The difference in the two surfactants is thought to be due to the more hydrophilic character of Chaser SD1000.

Figure 6 shows the interfacial tension-temperature relationship for Karamay crude in Karamay produced water containing SunTech IV and Chaser SD1000. Data in the absence of surfactant is also included in the Figure. The presence of ionic species, including high amounts of divalent cations in the water (Table 2), is beneficial to interfacial tension reduction with increasing temperature. The interfacial tension in the presence of SunTech IV was reduced by about three orders of magnitude at 200°C. This is a positive outcome for further reduction of residual saturation in the steam swept zone of the reservoir which, as will be shown below, may be crucial for foam formation.

Surfactant Partitioning

In core-size hot water displacement experiments using petroleum sulfonate surfactants, it was observed(13) that about 50 to 65% of the total surfactant was lost mainly due to the solubility of the surfactants into the oil. There is little information in the literature on the effect of temperature and brine concentration on the partitioning of surfactant between the aqueous and oleic phases. The present study carried out under static conditions was hampered by severe emulsion formation during mixing of the oil and aqueous surfactant mixture. Experiments were, therefore, carried out with little or no agitation. As a result the heating time employed was insufficient to reach steady-state. The data reported in Table 4 (75°C) and 5 (125°C) can only be compared within each separate set of experiments. However, the results show conclusively that under all conditions, Chaser SD1000 is superior to SunTech IV in terms of showing little or no tendency to partition into either Clearwater or Karamay oils. Friedmann and Jensen(3) reported that for Chaser SD1000, no significant partitioning into the oil could be measured. The conditions for these tests were not reported. Results of our study are also in general agreement with those reported(4) for SunTech IV at 205°C in which partitioning in the range of 20-30% was observed depending on initial surfactant concentration.

From Tables 4 and 5, it is tempting to conclude that for SunTech IV, partitioning is somewhat greater in Karamay than in Clearwater crude. However, since these experiments do not represent steady-state conditions, the increased rate of absorption may simply reflect the lower viscosity of the former compared to the latter. The same precaution applies to the effect of temperature on partitioning. In general, the effect of NaCl concentration (0 to 10 g/L) on partitioning appears to be small. This is consistent with the data reported by Al-Khafaji et al (14) who observed an effect on partitioning for NaCl concentrations above 10 g/L.

Foam Formation in the Presence of Residual Oil

The sand pack flow experiments were carried out to analyze foam behaviour in porous media in the presence of residual Clearwater or Karamay oils at elevated temperatures. Bitumen saturations in the pack were reduced using as displacing fluids hot water, hot water-surfactant, steam, steam-surfactant and hot water-toluene-surfactant mixtures. As expected from interfacial tension measurements in the absence of brine, the surfactants had little or no effect on reduction of residual oil. Steam injection after hot water injection produced little or no additional oil. Hot water injection reduced average oil saturations to 0.26 and 0.34 of the pore volume (PV) for Karamay and Clearwater oil respectively. Table 5 summarizes the results obtained and shows that for average oil saturation above 0.15, no foam was formed in the sand pack (mobility reduction = 1) with either surfactant. Below an average saturation of about 0.10, foam formation was observed with the extent of mobility reduction dependent on average saturations. As an example, Figure 7 shows the effect of residual oil on pressure gradient across the pack at various stages of Run #3. In cases where a foam was formed, the mobility reduction with Chaser SD1000 was slightly better than with SunTech IV.

For a field case, it is believed that typical steam-swept zone saturations are in the 10-20% range. The mechanism by which oil impedes foam formation in porous media is not understood. Nikolov et al.(14) concluded that interactions between an oil phase and foam lamellae are extremely complex and that oil droplet spreading, droplet size, pseudoemulsion film tension, and magnitude of the Marangoni effect may all contribute to destabilizing or stabilizing three phase foam structure. Friedmann and Jensen[3] have suggested that the oil droplets located at the expansion from the pore throats to the pore bodies could in some way impede the formation of a collar behind the interface and snap-off of a new bubble. If this is the case, then reservoir parameters (pore size distribution, wettability, oil distribution, etc.) and hydrodynamic forces (for example, injection rates) may provide the key for overcoming any detrimental effects of oil saturation.

Bitumen Displacement

Earlier experiments(9,10) in core-size test cells packed with field and laboratory prepared cores showed that foams could readily be formed in a high permeability (50 μm^2) channel emplaced between the injection and production ends of the core. In the present study, displacement experiments were carried out by injecting steam-only, steam-surfactant (2.5 g/L)-gas and steam- surfactant (5 g/L)-gas in successive 2 h (about 1 PV) periods. The steam rate was 5 g/min. Nitrogen gas was injected at 20 cm^3/min (run conditions), beginning shortly after the start of surfactant injection. Both surfactants were used with Clearwater cores (Runs 1 and 2), and based on these results, SunTech IV was chosen for the run with the Karamay core. Pressure drop (DP) and oil recovery curves for SunTech IV with a Clearwater core are illustrated in Figure 8. SunTech IV injection at 2.5 g/L with nitrogen gas resulted in an increase of DP by a factor of about five, indicating foam formation. Doubling the surfactant concentration caused an additional two-fold increase in DP. A concomitant increase in oil recovery due to foam formation is also clearly apparent.

A summary of the three runs carried out is given in Table 6. Under the conditions of these experiments, SunTech IV was more effective than Chaser SD1000 at producing a foam. At the lower concentration of 2.5 g/L, SunTech IV yielded a large increase in mobility reduction, while Chaser SD1000 injection was followed by a small decrease, indicating that no foam formation occurred. As a consequence, very little additional oil recovery was obtained with 2.5 g/L Chaser SD1000, while the same concentration of SunTech IV recovered a substantial amount of oil. At a higher concentration of 5 g/L, foam formation with Chaser SD1000 became apparent; however, mobility reduction was about the same as that with Suntech IV at the lower concentration of 2.5 g/L. This was likely due to the more hydrophilic character of Chaser SD1000, as evidenced by less of a tendency to both partition into the oil phase and lower interfacial tension. These results appear to conflict with surfactant performance at residual saturations reported above for concentrations of 5 g/L. However, the conditions of the two sets of experiments are very different. For example, the absolute permeability of the flow channel in the displacement tests is about 40 fold higher than that in the foam generation experiments. This emphasizes the importance of not generalizing results beyond the specific experimental conditions.

SunTech IV also performed well with the Karamay core, producing mobility reductions of 10 and 25 at 2.5 and 5 g/L respectively. The steam-only recovery was higher than that obtained with the Clearwater cores, probably due to the lower viscosity of Karamay oil. Consequently, the foam enhanced recovery was lower.

SUMMARY AND CONCLUSIONS

The results reported in this paper are part of a collaborative study to examine the benefits of using foam forming surfactants with steam-based processes for obtaining additional oil. Heavy oil and core samples from Canada and China and two commercial foam forming surfactants were used. Studies of the electrophoretic mobility, interfacial tension, surfactant partitioning, foam generation in the presence of residual oil, and foam injection to reduce steam mobility in core-size experiments were undertaken. Under the conditions of this study, the following conclusions can be drawn:

1. Despite differences in the physical, chemical and interfacial properties of the two crude oils, the surfactant type had the largest influence on the parameters examined.

2. Foam generation experiments performed in a 1.2 μm^2 sandpack at 180RC showed that foams could only be formed at oil saturations below about 0.15 PV.

3. Achievement of low interfacial tension may be needed to further reduce oil saturation in a steam-swept zone. For the two surfactants in the absence of added brine, an increase in temperature (25°-200°C) resulted in a general increase in crude oil/aqueous interfacial tension. Low interfacial tension (<0.1 mN/m) was achieved at elevated temperature with SunTech IV, depending on the ionic content of the aqueous phase. SunTech IV was more effective than Chaser SD1000 in reducing interfacial tensions under most conditions.

4. In partitioning experiments at 75° and 125°C, little or no losses into the oil phase were measured with Chaser SD1000. In contrast, a significant amount of SunTech IV partitioned into the oil phase.

5. In core-size displacement experiments, reduction of steam mobility by foam formation in a high permeability (50 μm^2) flow channel resulted in a substantial enhancement in oil recovery. SunTech IV performed better than Chaser SD1000, especially at lower concentration (2.5 g/L).

ACKNOWLEDGEMENTS

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Table 1
Physical and Chemical Properties of Clearwater and Karamay Crudes

Measurement	Temperature, °C	Clearwater	Karamay
Gravity, °API	15	10.4	19.7
Density, kg/dm^3	50	0.976	0.912
	100	0.946	0.876
	150	0.916	0.841
Viscosity, mPa.S	50	3172	369
	100	133	31
	150	24	9
	180	12	6
Elemental Analysis			
Carbon		84.3	85.6
Hydrogen		10.8	12.5
Nitrogen		0.4	0.6
Oxygen		1.1	1.2
Sulfur		4.4	0.1
Fractional Analysis			
Saturates		20.1	48.0
Aromatics		11.4	11.5
Polars I		16.5	9.2
Polars II		7.0	1.2
Polars III		23.1	18.9
Asphaltenes		16.6	2.0
Acid #, mg of KOH per g		1.4	5.0

Table 2
Analysis of Karamay Produced Water

Ion	Concentration, mg/L
Sodium	1450
Potassium	39
Calcium	222
Magnesium	12
Silica	48
Sulphate	64
Chloride	1950
Alkalinity	567

Table 3
Summary of Surfactant Partitioning Data at 75°C

A) 28 Days - No Agitation

Crude Oil	Surfactant	NaCl Conc.,g/L	Surfactant Conc. g/L	Surfactant Lost , %
Clearwater	SunTech IV	0	4.4	12
Clearwater	SunTech IV	10	3.9	22
Clearwater	SD1000	0	4.9	2
Karamay	SunTech IV	0	2.9	42
Karamay	SunTech IV	10	3.3	34
Karamay	SD1000	0	4.9	2

B) 21 Days - Some Agitation

Crude oil	Surfactant	NaCl Conc.,g/L	Surfactant Conc., g/L	Surfactant Lost , %
Clearwater	SunTech IV	5	4.7	6
Clearwater	SD1000	5	5.0	0
Clearwater	SD1000	10	5.0	0
Karamay	SunTech IV	5	3.5	30
Karamay	SD1000	5	5.0	0
Karamay	SD1000	10	5.0	0

* An initial sufactant concentration of 5 g/L was used in all experiments.

Table 4
Surfactant Partitioning Data at 125°C

A) 14 Days - No Agitation

Crude oil	Surfactant	NaCl Conc., g/L	Surfactant Conc. g/L	Surfactant Lost, %
Clearwater	SunTech IV	5	3.0	40
Clearwater	SunTech IV	10	3.7	26
Clearwater	SD1000	5	5.0	0
Clearwater	SD1000	10	5.0	0
Karamay	SunTech IV	5	3.7	26
Karamay	SunTech IV	10	3.1	38
Karamay	SD1000	5	4.9	0
Karamay	SD1000	10	5.0	2

B) 14 Days - Some Agitation

Crude oil	Surfactant	NaCl Conc., g/L	Surfactant Conc., g/L	Surfactant Lost, %
Clearwater	SunTech IV	0	2.4	52
Clearwater	SD1000	0	4.6	8
Karamay	SunTech IV	0	1.5	70
Karamay	SunTech IV	10	0.1	98
Karamay	SD1000	0	4.6	8

* An initial surfactant concentration of 5 g/L was used in all experiments.

Table 5
Mobility Reduction in a 1.2μm^2 Snad Pack in the Presence of Residual Oil at 180°C

Run #	Crude oil	Displacing fluid	Amount Injected, PV	Residual Oil, PV	Foaming Surfactant [a]	Mobility Reduction
1	Karamay	Hot Water	9	0.26		
		Hot Water & SunTech IV	15	0.16	SunTech IV[c]	1
2	Karamay	Hot Water	10	0.29		
		Hot Water & SD1000	4	0.29-0.25	SD1000	1
		Steam	8	0.25	SD1000[d]	1
		Hot Water&SD1000&Gas	10	0.25-0.15	SunTech IV	1
3	Karamay	Hot Water & SunTech IV	6	0.25	SunTech IV	1
		Hot Water&Toluene(20%)/IPA	3/1	0.06	SunTech IV	5
				0.06	SD1000	5.5
		Toluene/IPA	3/1	0	SunTech IV	10
				0	SD1000	13
4	Clearwater	Hot Water & SunTech IV	9	0.34	SunTech IV	1
		Hot Water & Toluene(20%)/IPA	3/1	<0.1	SunTech IV	7
				<0.1	SD1000	9
				<0.1	SunTech IV	7
		Toluene/IPA	3/1	0	SunTech IV	8

[a] Foam injection consisted of 0.7 cm^3/min aqueous surfactant and 7 cm^3/min nitrogen gas at run conditions.

[b] Mobility reduction is the ratio of the mobility of the gas/water mixture without surfactant to that with surfactant

[c] Increasing the gas rate from 3.5 cm^3/min to 7 cm^3/min to 23 cm^3/min while keeping the aqueous rate at 0.7cm^3/min had no effect on foam generation.

[d] Decreasing the temperature to 130°C and to room temperature had no effect on foam formation.

Table 6
Summary of Bitumen Displacement Runs[a]

Run #	Core	Injected Fluid	Avg. ΔP, kPa[b]	Mobility Reduction[c]	Oil Recovered, %	
					-Incremental-	-Total-
1	Clearwater	Steam Only	25	1	8	
		2.5 g/L SunTech IV	120	5	18	40
		5 g/L SunTech IV	230	9	14	
2	Clearwater	Steam Only	20	1	12	
		2.5 g/L SD1000	15	.75	4	27
		5 g/L SD1000	120	6	11	
3	Karamay	Steam Only	4	1	28	
		2.5 g/L SunTech IV	40	10	11	50
		5 g/L SunTech IV	100	25	11	

[a] Steam only, 2.5 g/l surfactant and 5 g/l surfactant were injected in successive 2 h periods. Steam injected rate = 5 g/min, N_2 injected at 20 cm^3/min, injection temperature = 170°C.

[b] After ΔP had levelled off.

[c] Mobility reduction is the ratio of the mobility of the gas/water mixture without surfactant to that with surfactant.

Figure 1
Schematic Diagram of the Sandpack Apparatus Used for Foam Generation Experiments

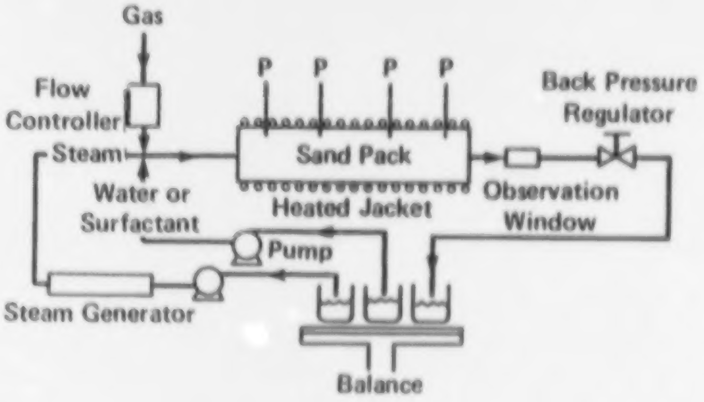

Gas
Flow Controller
Steam
Water or Surfactant
P
P
P
P
Sand Pack
Heated Jacket
Back Pressure Regulator
Observation Window
Pump
Steam Generator
Balance

Figure 2
Comparison of the Electrophoretic Mobility pH Relationships for Clearwater and Karamay Crude

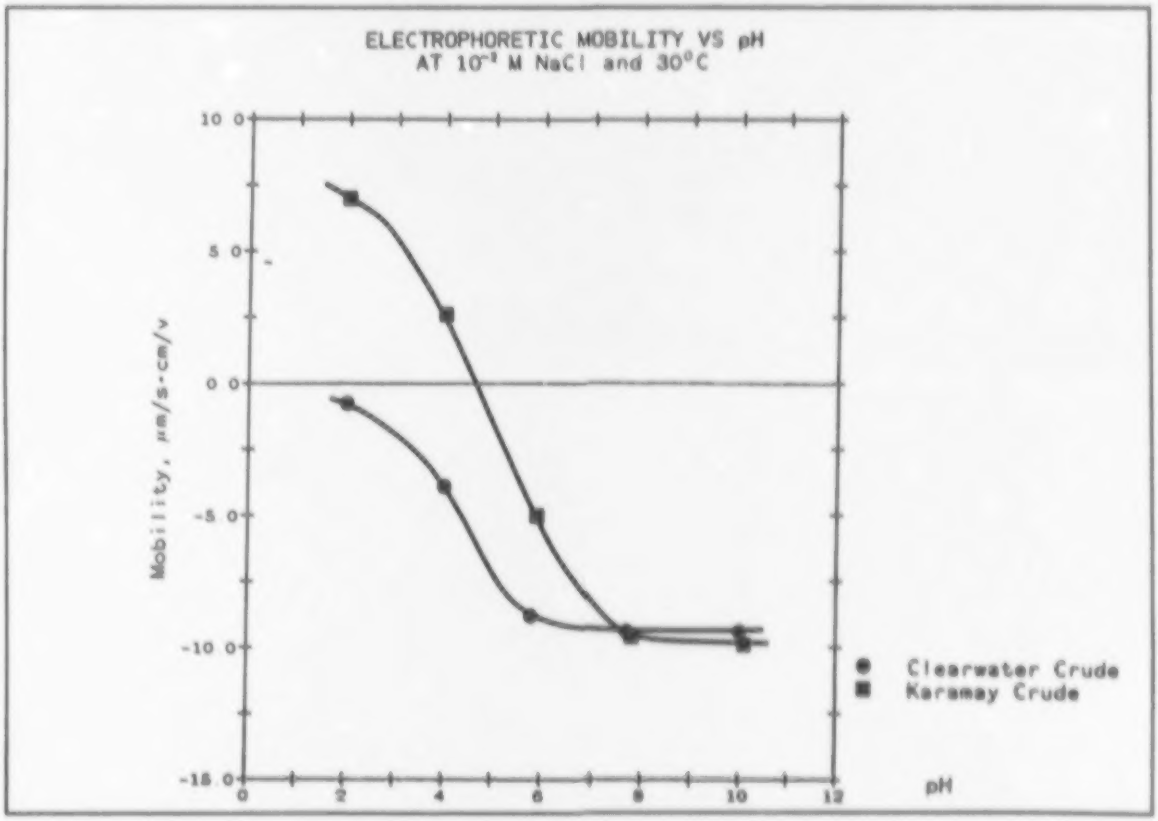


Figure 3
Comparison of the Interfacial Tension Temperature Relationships for Clearwater and Karmay Crude in Aqueous SunTech IV

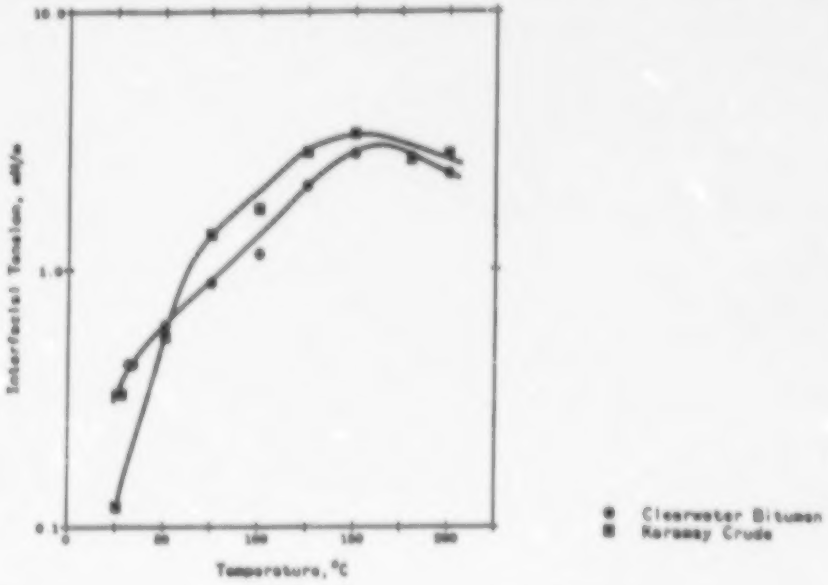


Figure 4
Comparison of the Interfacial Tension Temperature Relationships for Clearwater and Karmay Crude in Aqueous Chaser SD1000

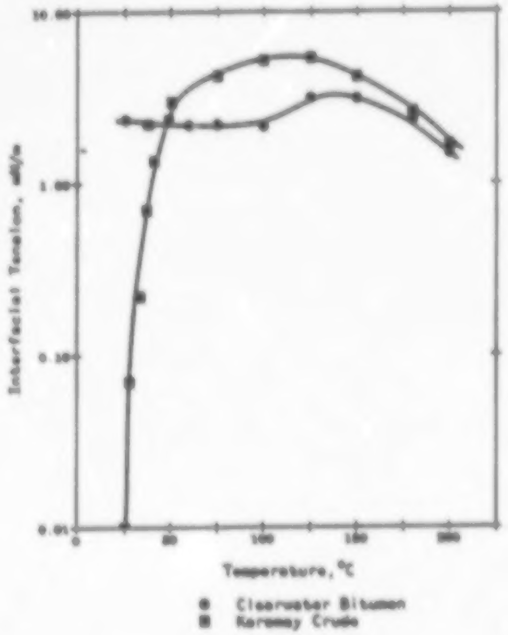


Figure 5
Effect of NaCl Concentration on the interfacial tension of Clearwater and Karamay Crudes in Aqueous SunTech IV and Chaser SD1000

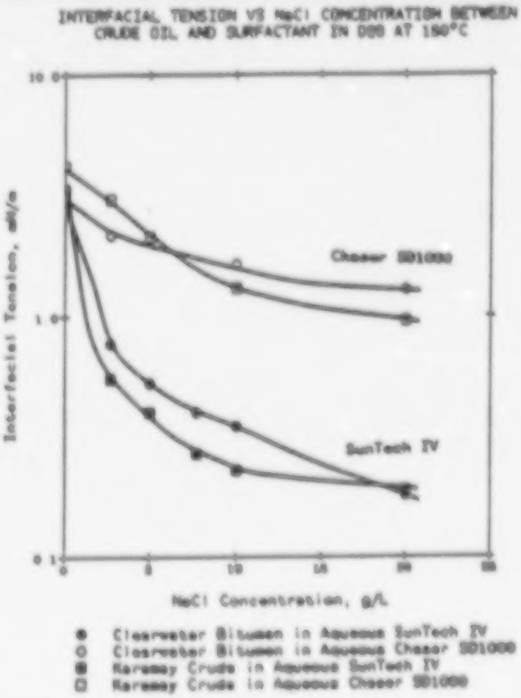


Figure 6
Effect of Temperature on Interfacial Tension of Karamay Crude in Formation Water With and Without SunTech IV and Chaser SD1000 Surfactants

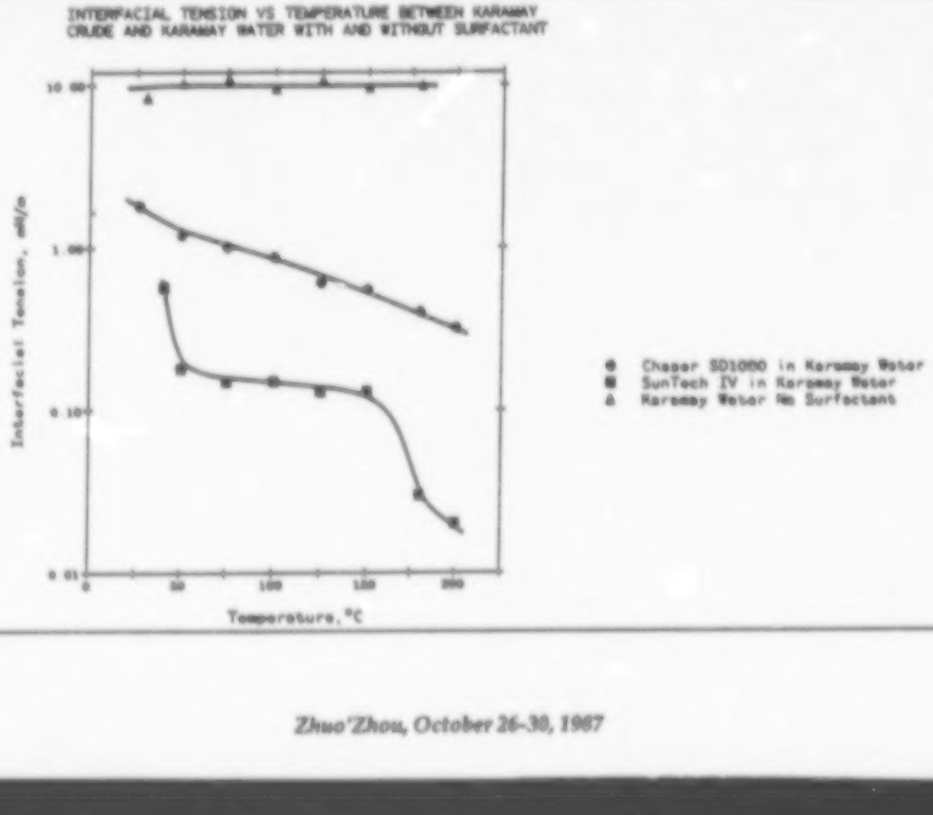


Figure 7
Effect of Oil Saturation (S_o) on Foam Formation in the Sandpack Apparatus

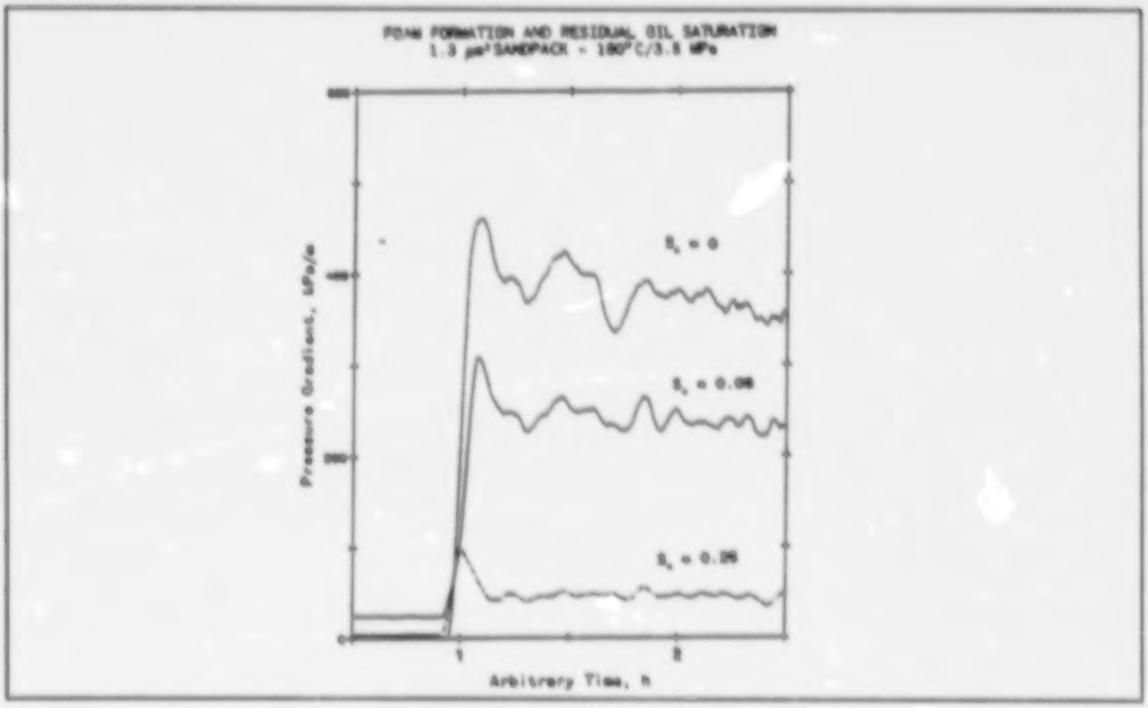
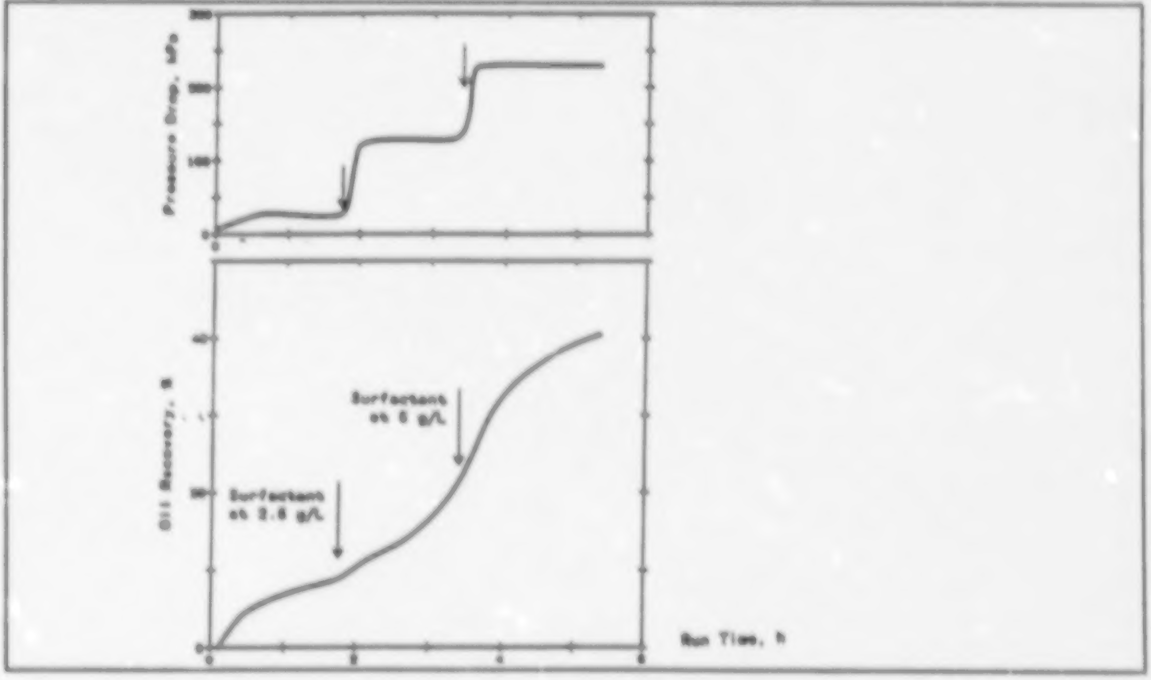


Figure 8
Oil Recovery and Pressure Drop Histories in Steam Followed by Steam-Foam Injection Using SunTech IV. N_2 Gas was Injected at 20 cm^3/min (run conditions) starting at 2 h of run time



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EFFECTS OF OIL VISCOSITY ON THE STEAM RECOVERY EFFICIENCY

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ABSTRACT

The main purpose of steamflood is to reduce oil viscosity. A numerical simulator was used to study the effects of formation thickness at 5 to 40 meters, and of oil viscosity at 500 to 50,000 cp. The results indicate that the steam recovery efficiency depends upon the formation thickness, especially for 5 to 10 meter thick reservoirs. The steam oil ratio, OSR, decreases rapidly as the viscosity increases. The results of this study provide a numerical data for steam injection viability.

INTRODUCTION

The Shu Guang reservoir is located Northeast of China. The depth of this reservoir is 1100 meters. It is impossible to produce oil by the primary depletion process because of its high oil viscosity at reservoir temperature. Hence steam injection is the only effective recovery process.However, one has to evaluate the economic feasibility based upon the reservoir fluid properties and formation thickness.

This paper studies the effects of oil viscosity on the steam injection.Many researchers conduct the study of the effects at pilot scale model. For a thin formation heat loss is a major concern and for the thick reservoir the steam override is a serious problem. Hence the purpose of this paper is to provide a numerical data for steam injection viability study.

1. BASIC CONDITION

The Shu Guang reservoir has a 1100 meter depth and the formation pressure is at 120 atm. The major portion of formation thickness exceeds 5 meters, with an average formation thickness is 34 meters. The oil viscosity range is from 500 to 50,000 cp. The formation has a good connectivity. During the past several years, a few cyclic steam stimulations (huff and puff) have been conducted, and the results are very encouraging.

A three-dimensional, three-phase numerical simulator which was solved by nine-point finite difference scheme was used in this study and it ran on a IBM-PC/XT.

First, two cyclic steam stimulations were matched for Well No 35 - 330 with well drainage radius of 100 meters, formation thickness of 100 meters, and oil viscosity of 10,000 cp at 50^{o}C. At the end of the two cycles, the actual productions were 27291 tons and 2506 tons for oil and water respectively. The simulator predicted 27102 tons and 2488 tons for oil and water respectively. Hence the error is 0.7 % for both oil and water. The parameters used are given in Table 1.

2. EFFECTS OF OIL VISCOSITY TO STEAM STIMULATION

A radial model with the center of radial grids 0.1, 1.6, 10, 15, 20, 30, 40, and 53 meters was used for steam stimulation. Our previous study indicated that the effects of the number of layers in the vertical direction were not large, hence one layer was used as shown in Figures 2-1 and 2-2 and also in Table 2.

Figure 2-1 shows that as the oil viscosity exceeds 10,000 cp at reservoir temperature, the oil recovery decreases drastically independent of the formation thickness and the effectiveness of steam stimulation decreased too. The following table shows the results.

Oil Viscosity (cp)	Recovery of Steam Stimulation for different H(m)			
	5	10	20	40
500	25.6			
1000	24.9	25.7		
4000	23.5	24.4	24.8	25.2
10000	21.0	21.8	22.0	22.7
50000	13.5	13.8	14.0	14.5

whereH(m) = Formation thickness in Meters.

For a thin formation, H = 5 to 10 meters, as oil viscosity (Uo) increases from 500 to 10,000 cp, ie Uo increases 20 times, the recovery decreases 4.7%. As Uo increases from 10,000, to 50,000 cp, ie 5 times, the recovery decreases 8%.

For a medium formation, H = 20 to 40 meters, as Uo increases from 4,000 to 10,000 cp: ie. 2.5 times, the recovery decreases 3.2 %. As Uo increases from 10,000 to 50,000 cp, ie 5 times, the recovery is 8.7 %.

From these results, as the oil viscosity increases, the oil recovery decreases rapidily. This is due to the fact that the injected steam is only able to heat the near wellbore area during the steam stimulation because of high oil viscosity. An area a little further away from the wellbore cannot be heated due to the oil temperature near wellbore which is not high enough to mobilize the oil, that is the viscosity reduction is not enough by steam stimulation. Figure 2-1 also shows that a thicker formation has a higher oil recovery than a thinner formation at the same oil viscosity. This is because a thicker formation has less heat loss and more oil reserve.

Figure 2-2 shows the relation between steam oil ratio, OSR, and oil recovery. For a formation thickness greater than 10 meters, the variation of OSR is very small. But the OSR of the 5 meter formation is less than the OSR of 10 meter formation, especially for Uo greater than 4,000 cp. From these results, we feel that there is a critical formation thickness, say less than 10 meters, in which the heat loss is greater than the heat stored. Under this condition, the effect of oil viscosity also increases, that is the OSR decreases and the effect of steam stimulation decreases too. The following table shows the OSR as a function of oil viscosity and formation thickness (H) during the steam stimulation.

Oil Viscosity (cp)	OSR at different formation thickness H(m)			
	5	10	20	40
500	1.335			
1000	1.299	1.310		
4000	1.146	1.282	1.291	1.313
10000	1.024	1.148	1.168	1.183
50000	0.494	0.701	0.732	0.758

This Table shows that for H = 10 meter case, the OSR decreases by 0.162, oil viscosity increases from 500 cp to 10,000 cp, and the OSR decreases by 0.470 as oil viscosity increases from 10,000 to 50,000 cp. For H = 5 meter case, the OSR decreases by 0.311m, as oil viscosity increases from 500 to 10,000 cp and the OSR decreases by 0.524 as oil viscosity increases from 10,000 cp to 50,000 cp. The OSR decreases rapidly if the oil viscosity is greater than 10,000 cp independent of the formation thickness. In the meantime, the effect of steam stimulation decreases rapidly too as the oil viscosity increases. In addition, the OSR for H = 5 meter case decreases faster than the case of H = 10 meter. This indicates that the effect of oil viscosity is greater than the effect of formation thickness.

Table 2 gives the simulation results of steam stimulation. The predicted values of oil recovery and OSR are higher than the field results from West of China. This is because Shu Guang field has a higher initial reservoir pressure and more initial reserve, hence the steam stimulation yields a better results.

3. THE EFFECTS OF OIL VISCOSITY TO STEAM FLOODING

A three dimensional model was used to simulate steam flooding and a comparison was made to two models with grids of 5*3*1 and 7*4*1. The results show that although the 7*4*1 model breaks through 70 days earlier than the 5*3*1 model, the oil recovery and OSR are similar for the two models. Hence we selected the 5*3*2 model for H = 5 to 20 meter case and 5*3*4 for H = 40 meter case as 3-D steam flooding models.

In addition, the simulation terminates at current OSR less than 0.15.Figures 3-1 and 3-2, and Table 3 give the simulation results.

Figures 3-1 and 3-2 show that the recovery efficiency for a thin formation is higher than a thick formation, but OSR is much lower and the economic profit is lower too. For a thick formation, even though the recovery efficiency is low the OSR is much higher. This illustrates that steam override is a serious problem in a thick formation hence the recovery efficiency is lower. However a thick formation has a larger reserve with strong drainage and lesser heat loss, hence this OSR is lower. On the other hand, for a thin formation heat loss is large but a better sweep hence the OSR is lower. The following tables give the simulation results of recovery and OSR for steam flooding.

Viscosity (cp)	Recovery (%) of Steam Flooding for Different H (m)			
	5	10	20	40
500	32.3			
1000	29.9	31.1		
4000	29.0	27.5	26.0	25.0
10000		24.0	24.6	23.1
50000			21.7	21.1

Viscosity (cp)	OSR of Steam Flooding for Different H (m)			
	5	10	20	40
500	0.151			
1000	0.139	0.233		
4000	0.114	0.185	0.219	0.242
10000		0.159	0.183	0.205
50000			0.151	0.153

These Tables indicate that for a 5 meter thin formation the OSR is very low, 0.151, despite the low oil viscosity, 500 cp. This is due to a higher heat transfer, hence a lower OSR. Also the injected steam is not effective in the reduction the oil viscosity due to heat loss. Hence for a thin formation, say less than 10 meters, the economic benefit is not good and it is not worth steam flooding because its net oil production is too small. As shown in the table, for H = 5 meter, the OSR equals 0.151 and the reserve is small; it also is not worth steam flooding. For H = 10 meter, the OSR equals to 0.159 at oil viscosity greater than 10,000 cp, it is at a marginal economic benefit, hence it takes a great risk. For H = 20 to 40 meter, a good result was obtained for the steam flooding with oil viscosity less than 50,000 cp. But as oil viscosity exceeds 50,000 cp, one has to be careful to conduct the steam flooding.

From the steam flooding simulation results, the effect of oil viscosity has a great impact. The higher oil viscosity gives the lower oil recovery and OSR. Especially for a thin formation, the effect of viscosity is greater than the thick formation.

4. ANALYSIS OF THE EFFECT OF STEAM STIMULATION AND STEAM FLOODING

Figures 4 and 5, and Table 4 give the simulation results of steam injection of the OSR and oil recovery as functions of oil viscosity and formation thickness.

From Figures 4 and 5, the higher oil viscosity gives a lower oil recovery and OSR. For a thin formation, although the oil recovery is higher than a thick formation, the OSR is much lower and the effect of viscosity is greater too.

Table 4 summarizes the simulation results of the effect of steam stimulation and steam flooding. The results indicate that we can use the OSR and the net oil production, (the net oil production equal to the cumulative oil produced minus the sum of the fuel oil and daily cost per well in term of oil), as screen criteria. The simulation results indicate that a 5 meter formation is not suitable for steam injection even though the oil viscosity is at 500 cp and OSR at 0.235; due to small amount of reserve it is very difficult to repay the investment. For a 10 meter formation and oil viscosity equal to 10,000 cp, the economic is marginal for the steam flooding. For a 20 to 40 meter formation, as oil viscosity is at 4,000 cp, it is worth steam injection, but as oil viscosity exceeds 50,000 cp, the economic is marginal for steam flooding. Hence one has to be prudent.

5. CONCLUSIONS

From the above analysis, we conclude as follows.

1. It takes a great risk to have steam injection for a formation thickness of less than 5 meter.

2. The effect of steam injection is good for a 10 meter formation with an oil viscosity less than 4000 cp.

3. It is ideal to have steam injection for a 20 to 40 meter formation and viscosity less than 50,000 cp.

4. The oil viscosity has a great effect in oil recovery and OSR of a steam injection process, especially for a thin formation.

5. The oil viscosity has a greater effect in steam flooding than in steam stimulation.

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Table 1
Input Data

Depth, m		1100
Initial Pressure, atm		120
Initial Temperature, °C		58
Initial Oil Saturation		0.6
Permeability (md)		2000
Porosity		0.3
Oil Viscosity, cp,	at 58°C	4000
	90°C	512
Oil Density, gm/cc		0.96
Pore Compressibility, 1/atm		0.001
Formation Thermal Conductivity, W/m-C		2.1
Overburden Thermal Conductivity, W/m-C		2.1
Irreducible water saturation		0.45
Residual Oil Saturation to water	at 20°C	0.3
	200°C	0.12
Residual Oil Saturation to steam		0.1
Relative Permeability Equations (5)		

$$Krw = 0.10 \times \left(\frac{Sw - 0.40}{0.60 - Sorw} \right)^{2.5} , \quad Krow = 0.9 \times \left(\frac{1 - Sorw - Sw}{0.60 - Sorw} \right)^{2.0}$$

$$Krog = 0.9 \times \left(\frac{0.48 - Sg}{0.45} \right)^{2.0} , \quad Krg = 0.2 \times \left(\frac{Sg - 0.02}{0.44} \right)^{1.5}$$

Table 2
The Simulation Results of Steam Stimulation

Thickness (m)	Viscosity (cp)	Cycle	Prod Time (Days)	Cum Inj (Tons)	Cum Prod (Tons)	N.O.P. (Tons)	Rec. (%)	OSR
5	500	3	500	1400	1870	1400	25.6	1.335
5	1000	3	500	1400	1800	1350	24.9	1.299
5	4000	3	450	1500	1720	1122	23.5	1.146
5	10000	3	450	1500	1537	962	21.0	1.024
5	50000	3	450	1500	989	414	13.5	0.494
10	1000	4	650	2800	3772	2880	25.7	1.310
10	4000	4	650	2880	3691	2800	24.4	1.282
10	10000	4	650	2880	3307	2417	21.8	1.148
20	4000	4	650	5700	7488	6038	24.8	1.291
20	10000	4	650	5700	6660	5372	22.0	1.168
20	50000	4	750	5800	4243	2823	14.0	0.732
40	4000	4	850	11600	15230	13500	25.2	1.131
40	10000	4	850	11600	13721	11479	22.7	1.183
40	50000	4	850	11600	8790	6548	14.5	0.758

Table 3
The Simulation Results of Steam Flooding

Thickness (m)	Viscosity (cp)	St Bk (day)	Prod Time (day)	Cum Inj (Tons)	Cum Prod (Tons)	N.O.P. (tons)	Rec (%)	OSR
5	500		900	36000	5400	1177	32.3	0.151
5	1000		900	36000	4992	732	29.9	0.139
5	4000		1000	44000	4752		29.0	0.114
10	1000	600	800	48000	11200	5600	31.1	0.233
10	4000	700	900	52800	9800	3600	27.5	0.185
10	10000	775	900	52800	8400	2200	24.0	0.159
20	4000	1350	1600	84800	18600	6800	26.0	0.219
20	10000	1400	1700	89600	16400	4700	24.6	0.183
20	50000	1500	1700	89600	13600	1900	21.7	0.151
40	4000	1300	1800	147200	35700	17990	25.0	0.242
40	10000	1350	1900	153600	31500	13000	23.1	0.205
40	50000	1900	2400	185600	28500	5838	21.1	0.153

Table 4
The Stimulation Results of Steam Stimulation and Steam Flooding

Thickness (m)	Viscosity (cp)	Prod Time (day)	Cum Prod (Tons)	OSR	Rec (%)	N.O.P. (Tons)
5	500	1400	9200	0.235	57.9	4000
5	1000	1400	8600	0.220	54.8	3400
5	4000	1450	8200	0.174	52.5	2200
10	1000	1450	18700	0.347	56.9	11300
10	4000	1550	17200	0.293	51.8	9200
10	10000	1550	15000	0.255	46.1	7000
20	4000	2250	33600	0.349	50.3	18800
20	10000	2350	29700	0.286	46.6	15400
20	50000	2450	22100	0.217	35.7	7500
40	4000	2650	67100	0.388	50.2	45000
40	10000	2750	59000	0.333	45.8	36000
40	50000	3250	46100	0.221	35.6	18900

Figure 1-1
Production Performance Curve of Well 35-330 in First Cycle

History Mathing of Well 35-330 in Shu Guang Oil Field

Cycle	Injecting time (day)	Cum-injection (ton)	Producing time (day)	Oil Produced (ton)		Water Produced (ton)	
				Real	Simulation	Real	Simulation
1	14	3134	410	12314	12328	827	787
2	24	4516	370	14977	14774	1679	1691
cum	38	7652	780	27291	27102	2506	2481

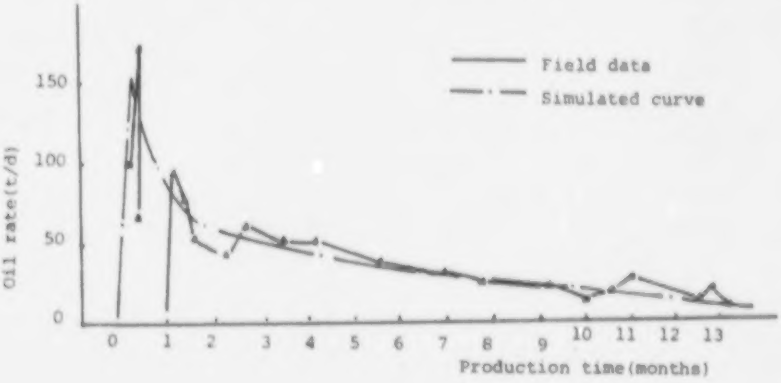


Figure 1-2
Production Curve of Well 35-330 in Second Cycle

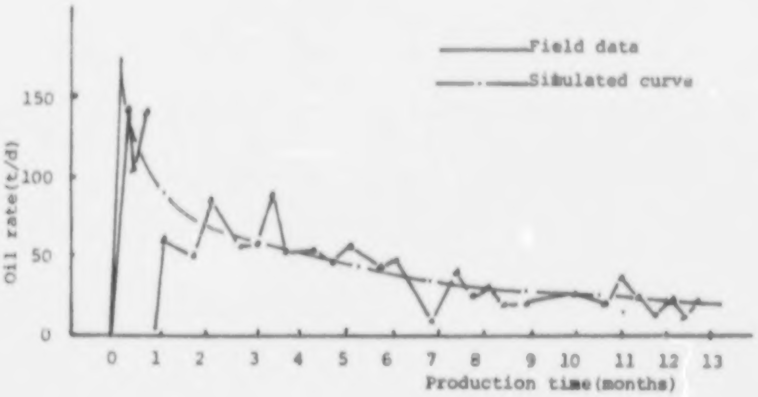


Figure 2-1
Effects of Oil Viscosity on Recovery by SteamFlooding

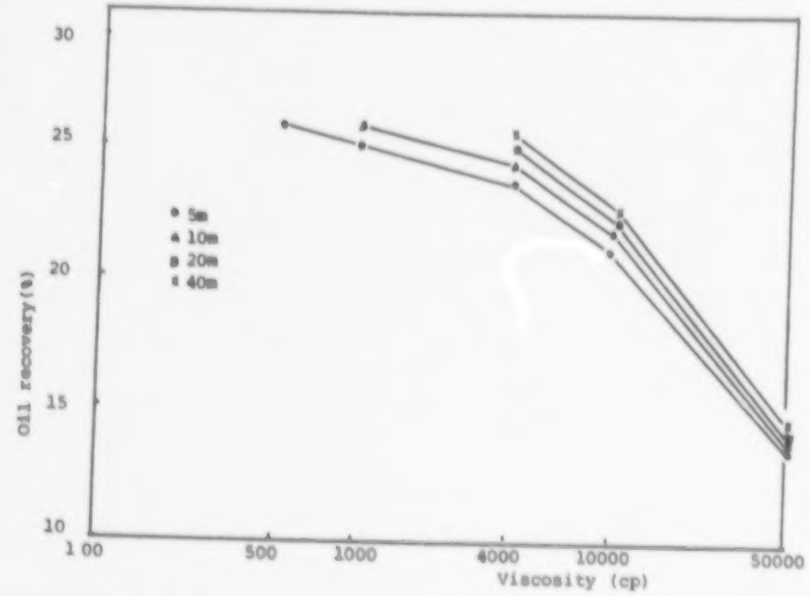


Figure 2-2
Effect of Oil Viscosity on OSR by Steaming Stimulation

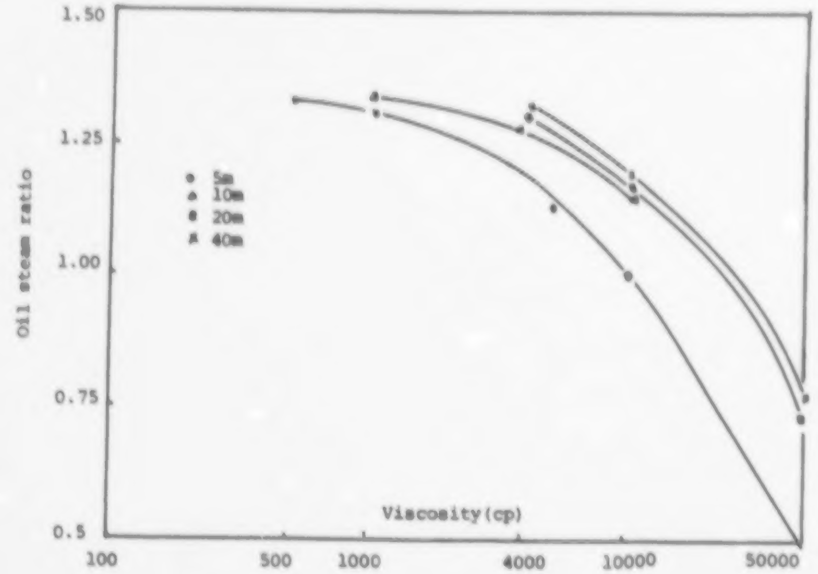


Figure 3-1
Effects of Oil Viscosity on Recovery by Steam Drive

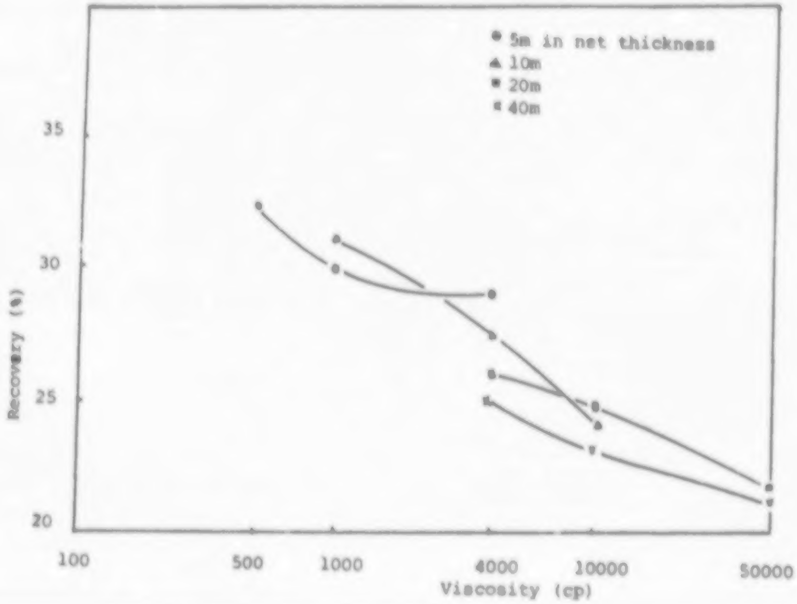


Figure 3-2
Effects of Oil Viscosity on OSR by Steam Drive

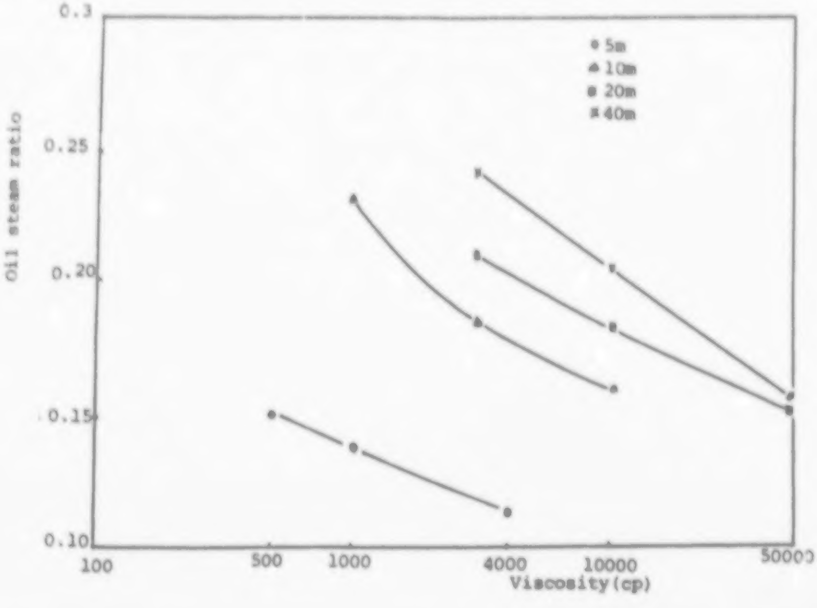


Figure 4-1
Effects of Oil Viscosity on Ultimate Oil Recovery

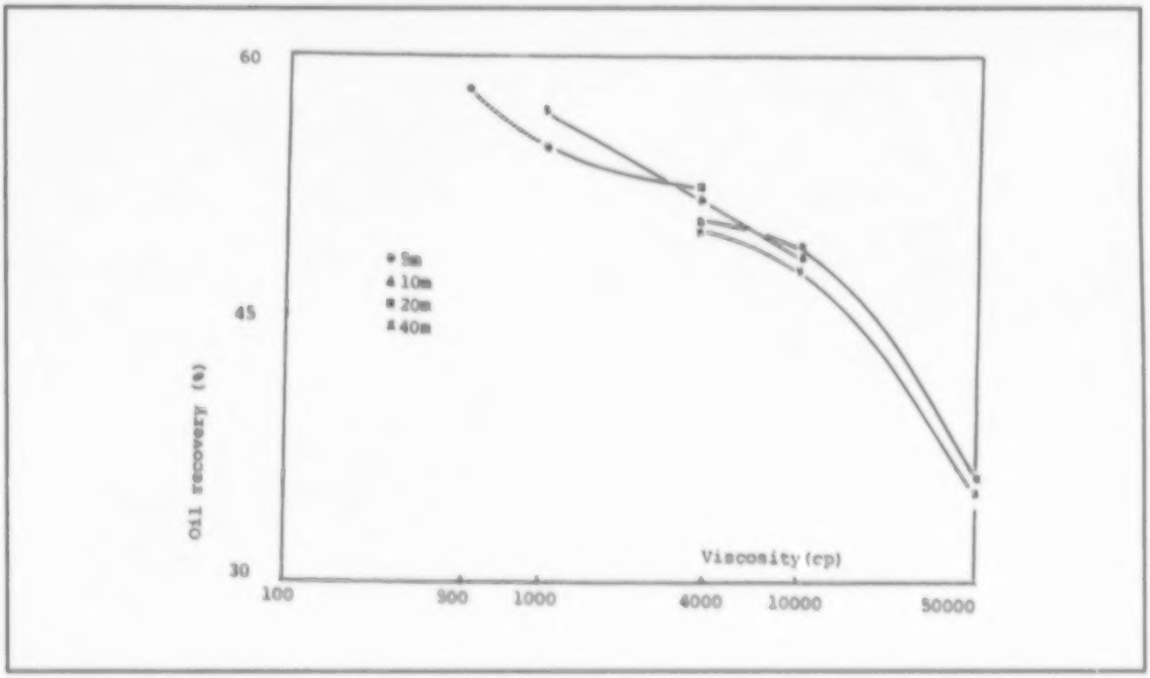


Figure 4-2
Effects of Oil Viscosity on Accumulative OSR

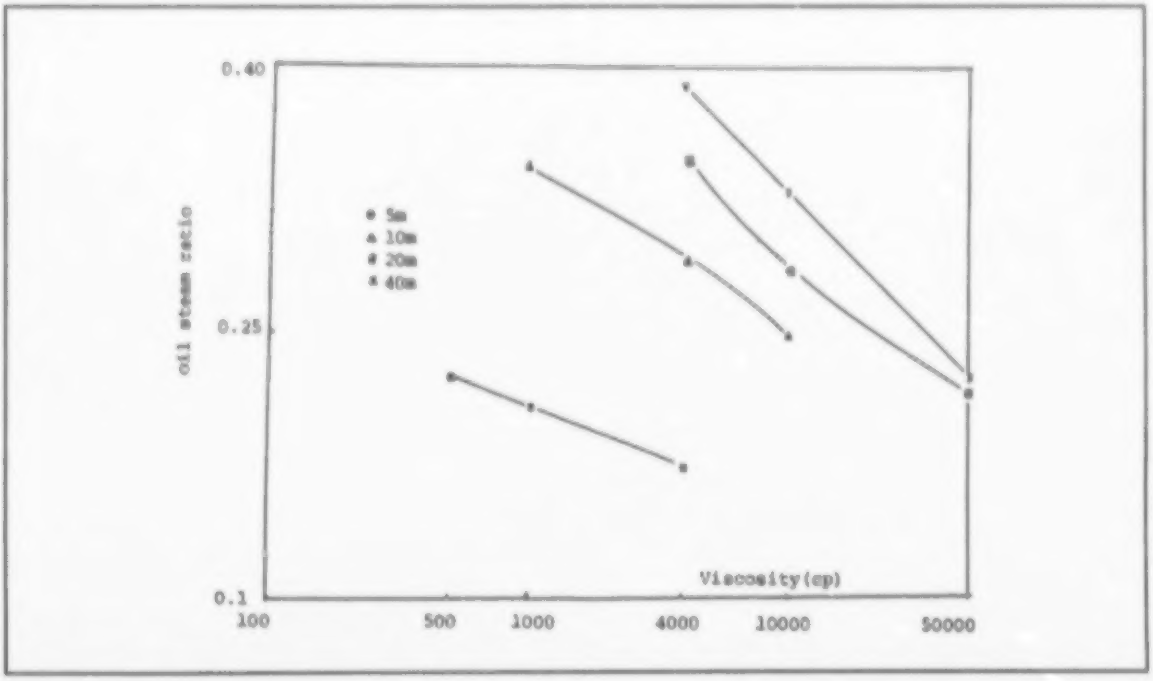


Figure 5-2
Effects of Formation Thickness on Oil Recovery

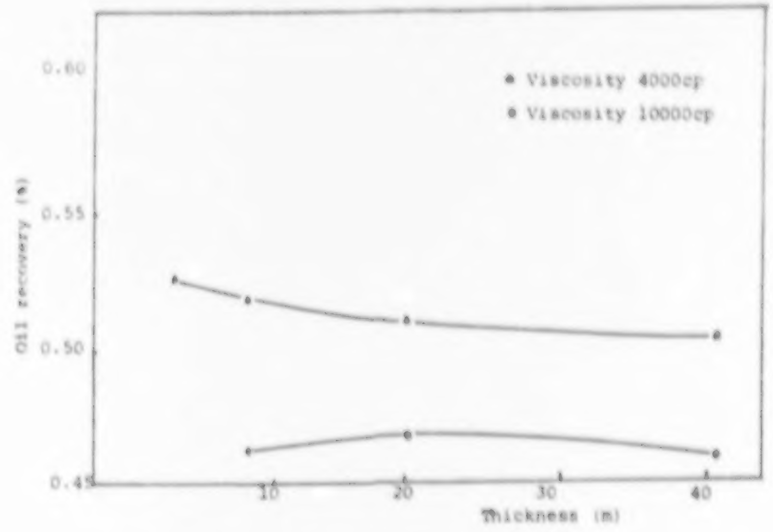
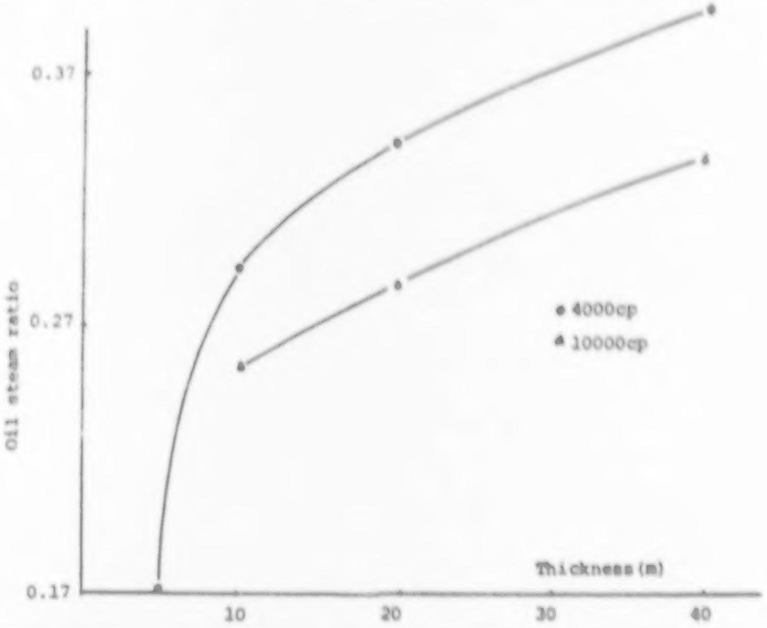


Figure 5-2
Effects of Formation Thickness on Accumulative OSR



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CHARACTERISTICS AND RECOVERY METHODS OF HEAVY OIL RESERVOIR IN LIAOHE OILFIELD

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ABSTRACT

This paper describes the types and characteristics of the heavy oilreservoir at Liaohe Oilfield. Heavy oils were classified based on thetypes of heavy oil accumulation and reservoir properties. According tothe classifications, different recovery methods werechosen, taking intoconsideration the reservoir depth and flow performance at undergroundconditions. The required operation techniques were obtained.

DISTRIBUTION CHARACTERISTICS OF HEAVY OIL DEPOSITS IN LIAOHE OILFIELD

Liaohe basin is a continental rift faulted basin, developed fromCenozoic. The development of the rift included various stages oftension, embryonic subsidence, deep subsidence and convergence, and thedifferent sandbodies which sedimented by the edge of the the basin. Together with the difference of paleotographs, the superposition ofmulti-sets of heavy oil reservoir were formed vertically in differentregions. Because of the deep burial and changes of biochemicalconditions, different heavy oils were formed.

Liaohe Oilfield is abundant in heavy oil resources, heavy oilreserve being about 1/3 of the total reserve. The present developmentfocuses on the up-dip part of the west slope in the west depressionwhich has maximum reserve. In addition, there are also many types ofreservoirs and oils in this field.

■ Vertical superposition of multi-sets of heavy oil reservoir

Eight types of heavy oil reservoirs were developed from Middle and Upper Proterozoic to Tertiary of Cenozoic. They formed the superposition of multi-sets. There are a variety of reservoirs, such as meta-quartzite, grainstone and sandstone. The sandstone reservoirs account for 8 to 9%. The sandstone reservoir is classified into massive, thick bedded, middle-thick bedded and thin bedded oil-bearing layers (see Table 1). Among the eight types of reservoirs, Shuguang oilfield is mostly developed, forming a superposition vertically.

■ Horizontal Distribution at South, North and Contural regions from the West Slope

South Region includes block jin 7, Huan 17, jin 45, jin 16, 9:40, and Huanxiling Oilfields. The main developments are the Lianhus Reservoir of the lower Third Member of Shahejie formation, Xing Longtai Reservoir at Second-First Member of Shuhejie Formation, and Yulon Reservoir at middle First Member of Shahejie Formation.

North region includes Gaoshen oilfield. The main developments are Lianhua Reservoir at Lower Third Member of Shahejie Formation and Gaoshen Reservoir at Upper Forth Member of Shahejie Formation.

Central region includes Part I of Shugnang Oilfield. The developments include quartzite Buried Hill reservoir at Dahongyu Formation, Middle and Upper Proterozoic, Dujiatai Reservoir at Upper Forth Member of Shahejie Formation, Lianhua, Dalinghe. Xinglongtar reservoirs at Lower Third Member - First Member of Shahejie formation, and Guatao Formation reservoir at Neogene.

■ Oil Properties

In Liaohe oilfield, there are three types of oil that can be classified based on their characteristics and compositional properties. Table 2 summarizes the basis of this classification.

- *Type I: The heavy oil is characterized by low viscosity, low density, and low bitumen content. It has good mobility at reservoir conditions. It deposits mainly in Gaoshen Oilfield and part I of Shuguang oilfield.*

- *Type II: The oil has high viscosity and density, and poor mobility at reservoir conditions. It is the primary deposit in the Liaohe oilfield, and mainly locates at Gaoshen and Huanxiling reservoirs.*

- *Type III: The oil has very high viscosity and density and the poorest mobility at reservoir conditions. Heating is required to improve mobility. It mainly deposits at Shu I and to a lesser extent, the Huanxiling reservoir.*

These three types of heavy oils generally deposit at certain buried depths. Type III heavy oil buries at a depth of less than 1000 meters. Type II heavy oil is generally at 1000 to 1200 meters, and in some cases, at depths greater than 1600 meters. Type I heavy oil is at 1200 to 1400 meters.

There are two possible origins of the heavy oil at Liaohe oilfield. The first is biodegradation, where the changes of the normal alkane and isoalkane cause the alteration of the oil compositions. Thus a "secondary oxidizing" heavy oil is formed. The heavy oil in Huanxiling oilfield belongs to this origin.

The second origin is that heavy oil is formed from low-mature oil stemming from a combination of inorganic oxidization and biodegredation. The heavy oil of Lianhua reservoir in Gaoshen oilfield belongs to this origin. Note that the origin of the heavy oil of Shuguang oilfield lies between the above-mentioned two origins.

TYPES OF HEAVY OIL RESERVOIRS AND THEIR DISTRIBUTION REGULARITY.

Reservoir Description and Classification

A common characteristic of heavy oil is poor mobility at reservoir conditions. In order to reduce viscosity, thermal recovery method has to be used to produce oil, instead of the conventional recovery processes. Consequently, classification of heavy oil reservoirs should be based on the geological conditions that are suitable for thermal recovery. In this study, the heavy reservoirs were classified as thermal recovery, based on domestic and foreign criteria, while taking into account heavy oil reservoir properties of Liaohe oilfield.

1. Items included in Reservoir Description are:

a) reservoir depth,

b) types of heavy oil,

c) formation thickness (especially single layer thickness),

d) sandstone coefficiency or sand-shale ratio,

e) petrophysical properties,

f) oil-gas-water relationships,

g) specific store coefficiency,

h) properties of fluids,

i) natural energy,

j) oil rheology.

It should be noted that formation thickness and net/gross sand ratio have the strongest influence on heat efficiency.

2. Types of Heavy Oil Reservoirs

The characteristics of heavy oil reservoirs can be divided into two types: clastic porous reservoir and Buried Hill metamorphic fractured reservoir.

Based on the single layer thickness and development of mudstone, the clastic reservoir can be divided further into four types: massive, thick bedded, middle-thick bedded and thin bedded reservoirs (see Table 3).

BURIED HILL METAMORPHIC FRACTURED RESERVOIR

Characteristics of Reservoir

The comparison of massive, bedded and buried hill reservoirs is presented as follows.

Massive Heavy Oil Reservoir: a typical example is the massive reservoir with top gas-cap and bottom water, such as Lianhua reservoir of Gaoshen Oilfield. Dalinghe massive reservoir has a similar description.

1. The reservoir traps are mainly lithologic and structural (or fault). They are characterized by

high oil saturation, high gas specific storage coefficiency and a simple oil-water relationship. Generally it is a singular oil and water system, with united oil-water interface and oil-gas interface.

2. Lithologic section is fine upward and coarse downward. Also, it is a combination of a sand-mud, being complex at the bottom. It belongs to deepwater turbidite sediments.

3. Oil-bearing zones are concentrated. Formation thickness is large with single-well thickness less than 100 meters and a maximum of 200 metres. Seventy percent of the single-layer thicknesses are more than 10 meters. The maximum value can be up to 60 meters.

4. Mudstone is not developed. The sand-shale ratio is high. Mudstone occurs in a form of unantineous interbedding.

5. Petrophysical properties are good. It is a highly porous and permeable reservoir.

6. The oil properties are characterized by "dilute upwards and viscous downwards".

Sandstone and Mudstone Interbedded Reservoirs

They developed mainly at the Upper Forth Member, Second-First Member of Shahejie Formation. The representatives are Xinglongtai reservoir, Yulou reservoir in Block Jinat, and Dujiatai reservoir in Shu I Oilfield. They are a combination of sandstone, conglomerate and mudstone which were formed with Delta Shallone-water sediments.

1. Reservoir is structural and mostly lithologic traps.

2. Single layer thickness is small, which distributes to sand-mud interbedding. 1 - 5% of the single thickness is greater than 10 metres, 35 - 68% is between 2- 10 metres, and 26 - 64% is less than 2 metres.

3. Oil-bearing well section is large and Mudstone is not developed. Thickness is large, distribution is continuous, and the sand-shale ratio is small.

4. Most reservoir is buried at a shallow level. Compaction is weak and oil sands are loose.

5. Oil-water relationship is complex, and often there are vertical multi-sets of oil-water combinations. Water and gas formed at the interbedded oil and gas reservoir.

6. The properties of oil change drastically in vertical section. There are the following three characteristics: first, viscous at the upper and lower levels and at the intermediate level, secondly, viscous at the upper level and dilute at the lower level, and thirdly, viscous at the lower level and dilute at the upper level.

Buried Hill Heavy Oil Reservoir

It is a paleomorphologic trap and belongs to internal latent reservoir which was developed on Middle and Upper Proterozoic. The reservoir is quartzite, with a fracture at oil pool. It is located mainly at North part of Shu I District in middle section of the west slope.

Table 4 shows the basic geological parameters of massive bedded and buried hill reservoirs.

STATUS OF HEAVY OIL DEPOSITS DEVELOPMENT

Development of Heavy Oil Resource

Until the end of 1985, some districts and blocks at Gaoshen Oilfield of North Region, Shugang Oilfield of Central Region and Huanxiling Oilfield of South Region have been either developed or are producing. Experiments were obtained for geological and development investigation of different types of heavy oil reservoirs. Engineering and operating techniques have been improving steadily. Basically, we are able to develop a variety of heavy oil reservoirs. Heavy oil production has gained an important position in the enhanced oil recovery at Liaohe Oilfield, and has made an important contribution to the increase of oil production. Table 5 summarizes the development status of three kinds of heavy oils of several heavy oil reservoirs.

Table 5 shows that the development of Gaoshen Oilfield is the best. About 92% has been developed.

As for the types II and II heavy oils, the degrees of developments are 48% and 59%, respectively. Among the four kinds of Clastic porous reservoirs, the massive and the middle thick bedded have better depletions of 89% and 80% respectively. As for reservoir depth, it was found that the reservoir of 1400 meters has the best depletion of 86% and in turn the reservoirs of 1200 - 1400 meters have 75%.

RECOVERY METHODS AND EFFICIENCY

■ Convention Pumping Production with Water Injection

This is applicable to reservoirs of 1200 meters or deeper. The oil viscosity should be 25 - 73 cp at reservoir conditions. During the pilot, the wells yield consistent productions. The productions are improved by water injection.

For example, Dalinghe Reservoir of Block 1-6-12 at Shugnang Oilfield was developed in 1978. In 1980, water injection began using the irregular reverse nine-spot pattern with 200 - 300 metres well spacing. The result of water injection is good. Daily oil production increased to 48 tons from 19 tons. As a result, oil production rate increased to 2.76% from 1.38%. Also, reservoir pressure climbed to 14.2 MPa from 10.8 MPa.

■ Conventional Pumping Production without Water Injection

This method is suitable for thin bedded middle heavy oil reservoirs where formation depth is high and oil mobility is good. It is not suitable for water injection, as in Gaoshen grainstone Reservoir in First District of Gaoshen Oilfield, for example. Because formation is thin and many mudstone breaks are present, neither water injection nor steam injection is suitable and only the conventional pumping production can be used.

■ Steam Stimulation after pressure decline by Conventional Pumping Production

This method is suitable for heavy oil reservoirs buried deeply. Lian Hua reservoir in Gaoshen Oilfield is an example. In this kind of reservoir, both oil viscosity and density are high. However, reservoir temperature and pressure are also high, so that the petrophysical properties are good. Oil viscosity in the reservoir is 518 - 605 cp. Therefore, oil is mobile at the first stage of production. It has been proven that oil can be produced by water injection in the beginning. Due to high reservoir pressure, the high-power pump has to be used to reduce pressure in order to produce oil and to prepare for thermal recovery.

As for the Lianhua reservoir in Gaoshen Oilfield, the depth of the formation is 1500 - 1700 metres. Oil viscosity at the surface is 2000 - 3000 MPa(s (at 50°C), reservoir temperature is 60 - 65°C, and reservoir pressure is 16 - 17 MPa. The reservoir is from thick to very thick massive sand-conglomerate turbidites with absolute permeability at 0.8 - $6m^2$. Excellent results were achieved using pre sand-proof completion. Daily oil production increased from 865 tons in 1983 to 3000 tons in 1986. Average single-well daily oil production went up to 15 tons from 11 tons.

■ Steam Stimulation

This method is suitable mainly for very heavy oil reservoirs and shallow-buried heavy oil reservoirs.

For very heavy oil, viscosity is generally greater than 10000 MPa(s and density is greater than 0.98 - 1.0. Oil viscosity at surface is 18000 - 10000 MPa(s. For these viscosities, thermal recovery methods must be used for better oil production.

Dalinghe reservoir of Block 1-7-5 in Shugnang Oilfield is a thickbedded reservoir with fringe water, in which the reservoir beds are turbitite sand-conglomerate stone. The formation depth is 960 - 1080 metres and oil viscosity at surface is 30000 - 40000 MPa(s (at 50°C). There is no oil produced by conventional well test. Good results were obtained by using steam stimulation pilot. During well flow, maximum daily oil production was as high as 152 tons. The average daily oil production is 110 tons. At present, there are 16 injection wells which give better results. For seven wells, the oil production per unit cycle exceeded 10000 tons and for one well the oil production per unit cycle exceeded 20000 tons.

Xinglongtar Reservoir in First District, Shunguang Oilfield, and Yulon Reservoir in Block 25, Huanxiling Oilfield also belong to this type of heavy oil reservoir. The formation depth of all these reservoirs is greater than 1000 metres.

For Shallone heavy oil reservoir, because of lower reservoir pressure, steam stimulation was used to accelerate the oil production, such as Xinglongtai reservoir in Block 21, Huanxiling oilfield.

Block 45 reservoir includes Xinglongtar Reservoir in second Member of Shahejie Formation and Yulon Reservoir in First Member of Shahejie Formation. Oil viscosity at surface in Xinglongtar Reservoir is 630 - 1900 MPa(s (at 50°C); in Yulon Reservoir it is 47° - 9700 MPa(s (at 45°C). Reservoir temperatures for these two reservoirs are 44.6 - 50°C. Steam stimulation pilot was used, and better production results were obtained.

For Xinglongtai Reservoir, a total of 31 wells were treated with steam stimulation. Accumulated injection steam is 69 thousand cubic meters and accumulated oil production is 26 thousand tons with the interval steam-oil ratio of 2.8.

For Yulon Reservoir, a total of 11 wells were treated with the steam Stimulation pilot. Accumulated injection steam is 31000 cubic metres, and accumulated oil production is 260000 tons with the interval steam-oil ratio of 0.87.

VI. CONCLUSIONS

Liaohe Basin, a continental rift faulted basin, was developed fron Cenozoic. It is rich in oil resources, especially heavy oils. Because of the complex geological structure, difference of paleotograph, and different backgrounds at various stages of rift development, vertical and complicated changes in plane were formed. These resulted in various types of heavy oil reservoirs and a wide range of oil properties in Liaohe Oilfield. Through research and practice of geological development, we were able to develop the different depth and different flow performance heavy oil reservoirs.

Table 1

Reservoir	Depth	Lithology	Void Space
Dahongyn quartzite	1000 - 1550	metaquartzite	fissure
Gaoshen	1320 - 1650	grainstone	pore
Dujiatai	670 - 2000	delta/bedded sandstone	pore
Lianhua	700 - 1700	turbidite sandstone conglomerate stone	pore
Dalinghe	960 - 1700	same as above	pore
Xing longtai	700 - 1250	delta bedded sandstone	pore
Yulou	700 - 1150	same as above	pore
Guantao	530 - 650	conglomerate middle thin sandstone	pore

Table 2
Classification Basis of Heavy Oil of Liaohe Oilfield

Classification standard/Oil type	Oil Viscosity (MPa's)		Oil density at surface (8/cm^3)	Content of bitumens (%)
	Underground	Surface (at 50°C)		
I	50 - 100	30 - 700	0.934 - 0.95	20 - 30
II	100 - 1000	700 - 8000	0.95 - 0.98	30 - 40
III	100 - 10000	> 8000	0.98 - 1.00	>40

Table 3

Criterion/ type	Type of Reservoir	Subdivision Criterion of Clastic Reservoir			
		Occurrence	Single Layer thickness (m)	Percent ratio of gross thickness	Sand-shale Ratio
I.	clastic	1. massive	>10	>60	> 3:1
		2. thick bedded	5 - 10	>60	2:1 - 3:1
	porous	3. middle-thick bedded	2 - 5	>60	1:1 - 2:1
	reservoir	4. thin bedded	>2	>60	<1:1
II.	buried hill metamorphic fractured reservoir				

Table 4
Geological Parameters of Different Heavy Oil Reservoirs

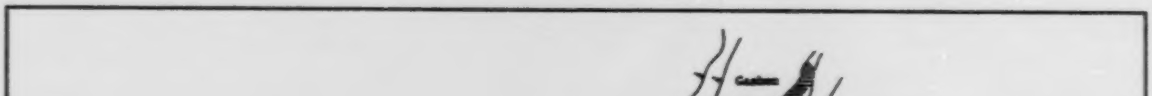
type of Reservoir	Single Layer thickness (m)	Depth (m)	Sand-shale ratio	Oil viscosity MPa*s (at 50°C)	Petrophysics		Oil-water relation
					porosity (%)	permeability (μm^2)	
massive	>10	960 - 1700	10:1	350 - 40000	23 - 26	1-3	simple singular gas cap bottom (fringe) water
thick bedded	5 - 10	700 - 1250	2:1 3:1	700 - 320000	30 - 32	0.3 - 1.5	complex multi-sets of fringe water (inter layer water)
middle-thick bedded	2 - 5	1000 - 1400	1:1 2:1	500 - 4000	22 - 24 22 - 24	0.2 - 1.0	same as above
thin bedded	>2	1400 - 2000	1:1 >1:1	300 - 700	21 - 23	0.2 - 1.0	same as above
buried hill		1085 - 1550		1500 - 30000			fringe (bottom) water

Table 5
Development of Heavy Oil Resources in West Slope (up to the end of 1985)

Oilfield	Item	Amount	Type of Heavy Oil			Type of Reservoir				Depth (m)			
			I	II	III	massive	thick bedded	middle thick bedded	thin bedded	> 1000	1000-1200	1200-1400	>1400
Gaoshen	dev. extent %	92 100	91		91.6	100		100				92	
	recovery method	Conventional pumping	Con. pumping	Con. pumping		Con. pumping	Con. pumping		Con. pumping				Con. pumping
Shuguang	dev. extent %	38 39	10.4	100	73		68.1	60.3		9.8	100	36.1	
	Rec. method	Con. pumping water inj. steam sti.	Con. p water inj.	Con p. con p.	soak	soak water inj. con p.		water inj con p.	water inj con p.		soak	water inj.	con. pumping
Huaxi-ling	dev. extent %	25	29.5						7.7	100			
	Rec. method	stimulate con. pump		soak con p.						soak	soak con p.		
Total	dev. extent	52.8	48	59	25	89	7.7	80	68	7.7	75	25	86

Figure 1

Oil Fields Distribution Map



22

THE FEASIBILITY STUDY OF STEAM INJECTION RECOVERY FOR THIN SANDS

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Hu J.P.
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ABSTRACT

Formation thickness is an important factor affecting the effectiveness of steam recovery processes. Whether or not heavy oil thin sand can be recovered with thermal processes is determined by the advancement in the recovery technology but more importantly by the economics, as development of thin sands is more risky financially compared with thick sand. In carrying out a feasibility study of thermal recovery processes for the Hulan Ergi thin sands, mathematical and physical models are employed to characterize the production of the thin sands by cyclic steam stimulation and steam drive processes. Meanwhile, optimization of steam injection and study of strategy for shifting from cyclic steam stimulation to steam drive process are conducted. Prediction of production performance of these processes on reservoirs of different thicknesses is also made based on the above studies. Using oil/steam ratio as an overall economic yard stick to determine the cost effectiveness of the thermal recovery processes, this article also presents detailed economic evaluation and conditions for the development of thin reservoirs with these processes.

INTRODUCTION

Feasibility of steam thermal recovery process for thin sands has been a subject of interests to many researchers. Many physical modeling and field testings had been conducted in the U.S.A. and Canada to investigate the effects of sand thickness on the performance of steam drive process. T.M Dosher[1] conducted laboratory experiments to study steam drive process in a scaled physical model with 7.6 and 21.3 meter sands. oil/steam ratios from the two experiments were close. Through simple mathematic analysis based on experimental data, he was able to conclude that a reasonably high oil/steam ratio could be obtained from a thinner sand. His experimental results are shown in Figure 2.1. C. Chu of the U.S.A. conducted statistics of the 28 steam drive field projects. Phillips Company succeeded in producing from the 4.6 meter Nacatoch reservoir in Smackover oil field with steam process and achieved a 0.24 oil/steam ratio. The statistical study of the steam drive process indicated that there were both success and failure of the process on reservoirs of 4 to 6 meter thickness. Criteria for the applicability of the process have not been fully developed; whether or not the process is applicable to thin sands is very much determined by reservoir fluid properties, flow characteristics and advancement in recovery technology. To encourage more research efforts into this area, C. Chu relaxed the lower limitation to 3 meters based on the published results by many investigators. Because of many ambiguity still existing in this area, it is of practical importance to study characteristics and production performance of steam drive process on thin sands.

Most of the heavy oil reservoirs in China have not been developed. Initial oil saturation and pressure of these reservoirs will be high when they are produced by thermal recovery processes for the first time. As this study has shown, initial oil saturation is a very important factor which can determine success or failure of the steam drive process.

So far China has not engaged in any field testing of the steam drive process and therefore possesses little operating experience of the process on thin sands. However, we have been conducting field testings of cyclic steam stimulation on thin sands such as Jinlou reservoir at Lanyang oil field with encouraging results. The reservoir is a newly discovered heavy oil reservoir of 6-8 meters thick where oil viscosity under reservoir conditions falls between 4,000 to 50,000 cp. Steam drive process was successfully tested on Lou-101 well where reservoir is 9.6 meter thick and oil viscosity 17,000 cp at reservoir conditions. During the test, 656 tons of practically hot water was injected in the first cycle. Cumulative production was 392 tons in 26 production days, or 15.1 tons/day on the average. Peak production rate was 29.0 tons/day. Production forecast indicates a cumulative production of 500 tons per cycle. The production would be much higher if boiler operation would allow injection of steam instead of hot water. These field experiments demonstrate the feasibility of cyclic steam stimulation on thin sands.

DESCRIPTION OF JULAN ERGI RESERVOIR

Hulan Ergi reservoir exhibits a linear belt in a north east orientation. The traps of the field pinches out upward. Formation forms a gentle monocline with dips between 1 and 2 degree. Production comes from Saltu formation member 2 and 3 which are uniform and concentrated. Hulan Ergi belongs to splay deposits exhibiting good field communications between wells. Typical cross sections are depicted in Figures 1.1 and 1.2. Because of contact of the reservoir at the downdip with an aquifer over an extended period of time, oil and water are intermixed in a vast area of a transitional zone where fluid properties are inferior to the updip region of the reservoir.

Crude oil under the reservoir condition is very viscous, about 1,000 to 4,000 cp so that it can not be produced with conventional recovery process. Also, sand production presents a considerable problem. Figure 1.4 shows viscosity-temperature curves for the crude oil and Table 1.1 the reservoir characteristics and fluid properties.

RESERVOIR MODEL STUDY AND BASIC PARAMETERS FOR NUMERICAL SIMULATION

Hulan Ergi reservoir is a single oil bearing formation with numerous thin intercalations of stable and impermeable clay band and shale. The thin intercalations tend to decrease the formation heating efficiency but, on the other hand, they assist in controlling steam override and therefore increasing vertical sweep efficiency. For thin formations, steam override is not a serious problem. The thin intercalations, if present in large quantity, would seriously affect the success of the steam thermal recovery process. According to the quantity and vertical distribution of the intercalations, Hulan Ergi reservoir can be divided into two typical reservoir models.

i) Hu-702 Well Model

According to the cross section of the formation at Hu-702 well, Figure 1.1, the formation is divided into two intervals by a single intercalation. The oil bearing intervals are fairly concentrated. The ratio of net thickness to gross thickness of the formation is 0.72 (5.85/8.12). Formation porosity is 30-35 %, initial oil saturation from core analysis is greater than 60 %.

ii) Hu-717 or Hu-718 Well Model

From the formation cross section, Figure 2.1, the formation at these two wells is characterized by multiple thin intercalations . For Hu-718 well, there are 20 intercalations of 4.1 meters in total thickness or 0.2 meter per layer on the average. The formation is interspersed with sand-clay interlayers. The net and gross thickness at the Hu-718 well are 6.7 and 10.8 meters respectively; for Hu-717 well, they are 6.3 and 10.3 meters. The net to gross thickness ratios are greater than 0.6. Porosity is 30% and average initial oil saturation 60 % with the maximum value reaching 80 %.

From the formation cross sections of the above three wells and well logging, the formation is confined by overlying and underlying layers made up of stable clay which provide good sealing effect for the steam thermal recovery processes. Based on the permeability data from core analysis, the formation is heterogeneous, its sedimentary rhythm is not clear and can be taken as a compound rhythmic sediment. The core analysis indicate close relationship between porosity, permeability and oil saturation. Because the formation is fairly thin and reservoir properties are quite uniform, it is reasonable to employ reservoir parameters averaged over the entire formation interval for the mathematical simulation.

Because of heat transfer mechanism in the steam injection process,the position of the intercalation becomes quite important[4]. If it is at the middle of the formation, it behaves like a heat reservoir absorbing heat during steam injection and releasing heat during production. The impact on the production is positive. If it is located near the top or the bottom of the reservoir, the effect becomes diminished. Also, the effect due to heat transfer mechanism of a intercalation at mid interval is greater in a thicker formation, and is quite small in a thin reservoir. In modeling thin formation, there is therefore no need to divide the formation into small grids.

The Hu-702 well model is used to simulate Hulan Ergi reservoir using the simulation parameters taken from Table 3.1 and viscosity temperature data from Table 3.2.

PHYSICAL AND NUMERICAL MODELING OF THERMAL RECOVERY FROM THIN SANDS

■ i) Cyclic Steam Stimulation

Results from the numerical simulation of the CSS process on different formation thickness are presented in Table 4.1. In a multi-cycle steam stimulation operation, total cycle injection volume increases 15 % by each cycle to ensure that same amount of heat is injected to the formation for propagating heating zone and increasing production. The results from the simulation indicate that, regardless of formation thickness, peak production rate and oil/steam ratio decrease with production cycle. However, within the formation thicknesses under study, the cumulative oil/steam ratios are all higher than the economical limitations. The smallest cumulative oil/steam ratio obtained from the 3 meter thick sand after the fifth cycle is as high as 0.8. In the numerical simulation, the steam injection intensity, i.e amount of inject steam/meter reservoir, is kept the same for different thickness. This explains why the cumulative oil/steam ratios for different thickness are fairly close although their productions are quite different. Although oil/steam ratio is an important economic composite index for steam recovery processes, the small cycle production and high production costs of the cyclic steam stimulation make it necessary to undertake more detailed economic evaluation to justify commercial development of thin sands with the process.

■ ii) Steam Drive Process

Numerical model was used to simulate production from cyclic steam stimulation followed by steam drive processes for two cases. In case I, process switching occurs after the third cycle production by a producer with cyclic steam process and in case II, it occurs after the fifth cycle by a injector. Results from the two cases are given in Table 4.2 Overall production performance in term of oil recovery and oil/steam ratio is about the same for the two cases. However, with smaller production cycle, operating costs will be lower, project life shortened, and production accelerated. For thin sands, production cycle of the cyclic steam stimulation should be kept to the minimum, and process conversion should be done as soon as it is feasible.

Due to heat dissipation through the overlying and underlying layers, heat efficiency is generally poor for thermal recovery of thin sands. Figure 4.1 presents the simulation results on different sand thicknesses, heating efficiencies and injection times. For 4, 5 and 6 meter sand, the average heating efficiency on the reservoir is only 30 %, with the remaining 70 % heat lost to the surrounding formations.The results indicate that increase in steam injection rate during steam drive would accelerate steam front and increase the production performance.

A scaled physical model was used to investigate the effect of steam injection rate on steam drive[5]. Results are given in Table 4.3 and Figure 4.2 and 4.3. These figure show that higher injection rate is beneficial to oil recovery and steam/oil ratio. Their relationships are, however, not linear and exhibit an optimum injection rate. By conducting optimization tests with the physical model, an optimum injection rate of 132 tons/days was obtained for 6 meter reservoir model with 80 meter well spacing between a producer and an injector. Because heat loss from the physical model is greater than from the numerical model, steam breakthrough time is longer, and optimum injection rate higher. In field production operation, injection rate was determined largely by formation injectivity. From the temperature profiles with high and low injection rates as shown in Figure 4.4, steam override was quite serious when the injection rate was low. It diminished as injection rate increased, and showed a tendency of turning into a frontal drive. Perhaps this could be an important oil sweeping mechanism for increasing production performance.

■ iii) Production Performance of Cyclic Steam Stimulation and Steam Drive

As discussed earlier, cyclic steam stimulation followed by steam drive is more effective than direct steam drive. Production cycle of the cyclic steam stimulation should, however, be kept to the minimum. Table 4.4 summaries the production performance for a 100 meter and a 140 meter well spacing between a producer and an injector and for difference formation thicknesses. Production is accomplished with cyclic steam stimulation to the third cycles before switching to steam drive.

ECONOMIC EVALUATION OF THERMAL RECOVERY FOR THIN FORMATIONS

An economic evaluation of thermal recovery for thin formations at Hulan Ergi reservoir was conducted based on the results from the physical and numerical modeling discussed earlier. The evaluation involves predictions of annual production and annual injection volume for the development of the reservoir thicker than 5 meters. The project calls for annual expansion of production area by 1.0 Km, employing 5 spot well pattern with 100 meter well spacing between a producer and an injector. Total production period for a single well is estimated to be 5 years, with the well producing initially with cyclic steam stimulation followed by steam drive process. The project for developing the 9.4 Km reservoir at least 5 meters thick takes 13 years to complete and produces 4.4 million tons of oil. Recovery is estimated to be 44 %, average annual production to be 338,000 tons, and peak annual production to be 530,000 tons(stable over 3 year period). Cumulative steam injected is 19 million tons over the entire production period, and cumulative oil/steam ratio is 0.232. Using the economic indexes developed by the Institute of Downhole Technology, Daqing Oilfield, economic evaluation for developing Hulan Ergi thin reservoir was made[6] to establish the relationships between production cost, production volume and steam injection volume as shown in Figure 5.2. Production cost tends to increase with production period, and shows a drastic rise at the ninth year when the project ceases to expand into new area. Even with the high production cost, the project is still profitable under favorable oil price.

In order to find out the lower limit in formation thickness, evaluation of production cost and oil/steam ratio from thermal recovery from reservoirs of different thickness was conducted. The results are shown in Figure 5.2. The composite oil/steam ratio from the production of Hulan Ergi reservoir with cyclic steam stimulation and steam drive is 0.253 from the study. The lower limit in formation thickness is 5.5 meters above which the production operation by steam injection can be financially successful under favourable oil price. This study shows that production of formation thinner than 5.5 meters should not be considered as it will not be economically feasible.

CONCLUSIONS

☐ *1. Steam override in thin sands is small and becomes smaller in the presence of thin intercalations in the formation. Because of small steam override, the entire formation interval is heated by injection steam.*

☐ *2. Because of heat loss to the overlying and underlying layers and heat brought up to the surface in produced fluids, only a small portion of the injected heat remains in the formation. Formation temperature drops very rapidly and peak production period is very short. Well production changes very quickly from a flowback stage to pumping stage. Duration of production cycle period is determined largely by viscosity of reservoir fluids and its energy content; the effect due to viscosity is more pronounced in thinner reservoir.*

☐ *3. Oil/steam ratio from thermal recovery of thin formations with superior reservoir characteristics is generally quite high. The cycle production is, however, much lower and production cost significantly higher than those of thick formations. Detail economic evaluation should be taken to determine whether or not it can be commercially developed.*

☐ *4. For thick reservoirs, production rate from cyclic steam stimulation is generally higher than steam drive. For thin reservoirs, the reverse is true due the requirement for a high injection rate during steam drive to overcome heat loss.*

☐ *5. Production cycle has little effect on the overall production. Since production rate from steam drive is higher than cyclic steam stimulation, project life would be shortened considerably if cyclic steam stimulation is kept to a minimum cycle of about three.*

☐ *6. Sweep efficiency is higher in thin sands due to smaller effect from steam override. This was verified by laboratory experiments which indicated that, for the same temperature, residual oil saturation in core after steam drive was considerably lower than after hot water flood. Oil recovery is therefore determined primarily by the volume of steam chamber. Because of high heat loss in thin sands, the effects of better steam quality and higher injection rate would be more prominent for thin sands than for thick sands.*

☐ *7. Production cost from thin sand steam operations is high and increases with production year. For a 5 to 6 meter thick sands, production with either cyclic* *steam stimulation or steam drive is costlier than the conventional method.*

❑ *8. Development of a thin sand by thermal recovery processes is economically feasible only if oil/steam ratio is higher than 0.235 and reservoir thicker than 5.5 meters.*

ACKNOWLEGMENT

This paper was completed under the advises of Mr. W.Z. Liu, Chief engineer and Mr. R.C. Liang, senior engineer. The institute of Downhole Technology of Daqing oilfield provided detailed geological information and supports. Thanks are due to many fellow researchers in the Thermal Recovery Laboratory of RIPED for their valuable help.

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Table 1.1
Reservoir Parameters and Fluid Properties

Gross thickness, meter	3.0 - 11.0
Net thickness, meter	3.0 - 6.0
Net/gross thickness ratio	0.5 - 0.7
Porosity, %	30
Permeability, md	2300(average)
Initial oil saturation, %	60
Dip angle, degree	2 - 4(E-W)
Reservoir temperature, degree C	18
Crude oil viscosity	1000 - 4000 cp
Specific gravity of oil	0.92
Depth, meter	450- 500
Reservoir pressure, atm	50
Wax content, %	12 - 19
Asphaltene & Resin, %	12.7 - 19
Initial distillation point, degree C	210 - 260
Distillation fraction at 250 C, %	5

Table 3.1
Parameters of Well 702 for Reservoir Simulation

	Oil Formation	Inter-calculation	Oil Formation
Net thickness, meter	1.5	2.3	4.3
Porosity, %	30.0	0.00	30.0
Vert. permeability, md	230.0	0.0	230.0
Horizontal permeability, md	2300.0	0.0	2300.0
Oil saturation, %	60.0	10.0	60.0
Water saturation,%	40.0	90.0	40.0

Table 3.2
Viscosity - Temperature Data

Temperature, °C	Viscosity, cp
18	4242.4
35	1084.1
60	368.4
80	92.1
100	41.2
120	18.4
130	16.4
142	15.4
150	14.1

Table 4.1
Effect of Formation Thickness on Cyclic Steam Stimulation to Five Cycles

	Net Formation Thickness, Meters			
	5.8	5.0	4.0	3.0
Cumulative Steam Injected, tons	3370	2850	2390	1800
Cumulative Oil Produced, Tons	2734	2321	1814	1283
Effective Production Period, Days	680	675	680	675
Oil Production Rate, Tons/Day	4.0	3.4	2.7	1.9
OSR At 5th Cycle	.50	.53	.49	.43
Cumulative OSR	.81	.76	.76	.71

Table 4.2
Effect of Steam Cycle on Overall Recovery Efficiency

	Five Cycles			Three Cycles		
	PV=1.0	PV=1.2	PV=1.5	PV=1.0	PV=1.2	PV=1.5
Cum. Oil Produced, Tons	8972	9500	10433	8945	9768	11047
Oil Recovery, %	43.2	45.3	50.3	43.1	47.0	53.2
Oil/Steam Ratio	0.217	0.196	0.178	0.246	0.225	0.206
Production Years	4.6	5.2	5.7	4.0	4.3	4.8
Recovery Rate, % OIP/year	8.8	8.8	8.8	10.8	10.9	11.0

Table 4.3
Effect of Injection Rate on Steam Drive by Physical Simulation

	Injection Rate, Tons/Day					
	32	54	64	91	138	177
Cumulative OSR	.126	.179	.183	.195	.230	.230
Recovery, %	22.2	35.3	51.7	55.6	69.0	72.0
Breakthrough Time, PV		2.53	1.90	1.23	1.12	0.85
Production Time, Years		2.16	2.44	1.67	1.21	1.00
Total Oil Produced, 10,000 Tons	0.44	0.75	1.03	1.06	1.34	1.45
Net Oil Produced, 10,000 Tons	0.15	0.41	0.58	0.62	0.87	0.94

Table 4.4
Effect of Formation Thickness on Overall Recovery Efficiency

	Well Spacing=100m			Well Spacing=140m		
Formation Thickness, Meters	5.8	5.0	4.0	5.8	5.0	4.0
Cumulative Oil Produced, Tons	9768	7696	5441	15207	12798	9651
Oil Recovery, % OIP	47.0	43.0	38.2	37.1	36.3	34.2
Cumulative OSR	.225	.206	.182	.181	.177	.167
Production Time, Years	4.5	4.2	3.9	6.6	6.2	5.6
Recovery Rate, % OIP/year	10.4	10.2	9.7	5.6	5.8	6.1

Note: Injected Pore Volume=1.2

Figure 1.0
Isopach Map of Oil Sand Formation

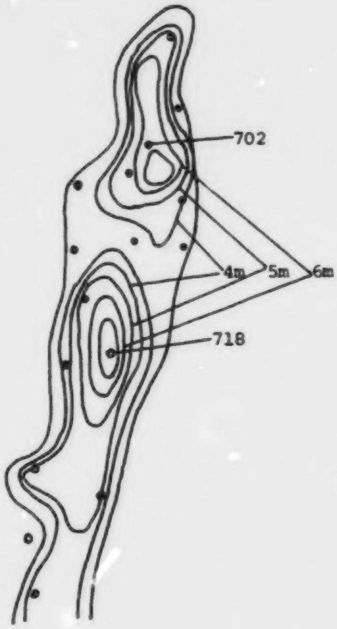

702
4m
5m
6m
718

Figure 1.1
Cross Section of Formation Heterogeneity of Well Hu 702

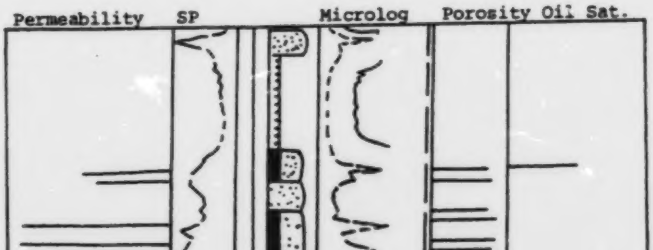

Permeability
SP
Microlog
Porosity
Oil Sat.

Figure 1.2
Cross Section of Formation Heterogeneity of Well Hu 718

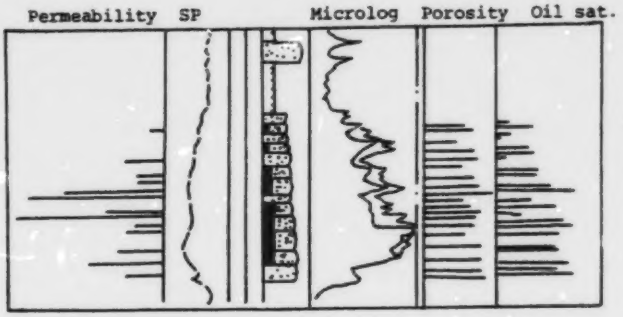


Figure 2.1
Effect of Formation Thickness on Cumulative Oil/Steam Ratio

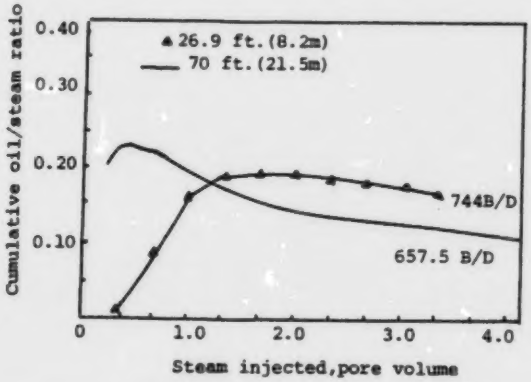


Figure 3.1
Grid of Numerical Simulation for Steam Stimulation

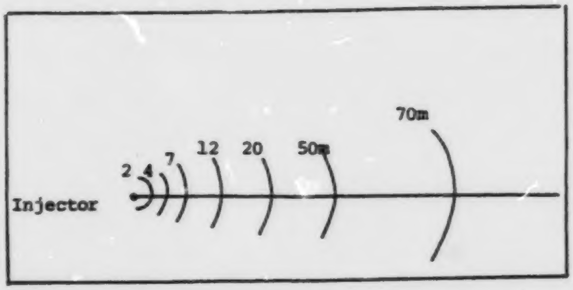


Figure 3.2
Grid of Numerical Simulation for Steam Drive

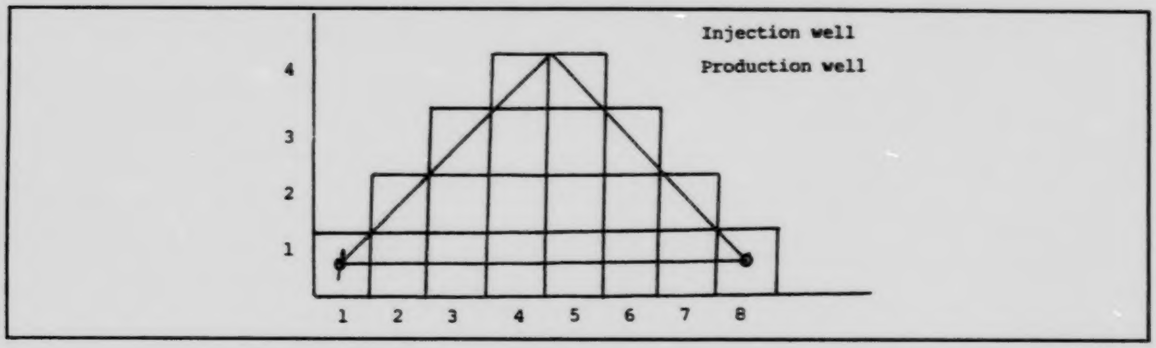

Injection well
Production well
4
3
2
1
1
2
3
4
5
6
7
8

Figure 4.1
Relationship of Heating Efficiency vs. Injection Time for Various Formation Thickness

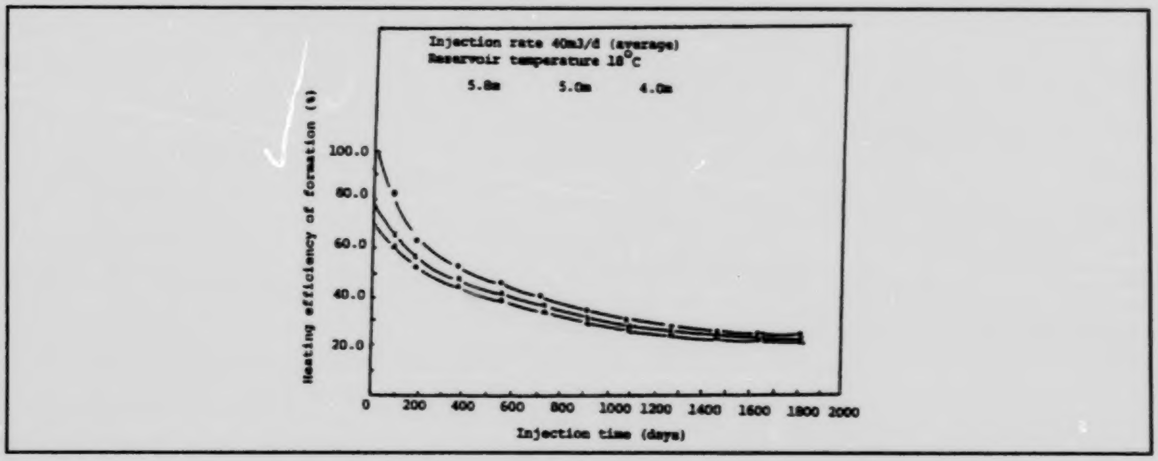


Figure 4.2
Effect of Injection Rate on Recovery by Physical Model

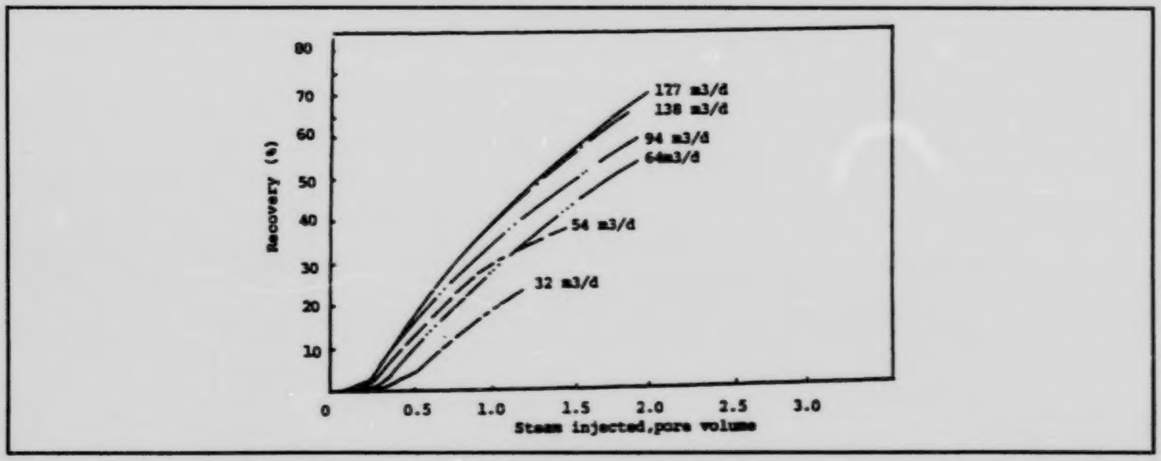


Figure 4.3
Effect ofInjection Rate on Oil/Steam Ratio by Physical Model

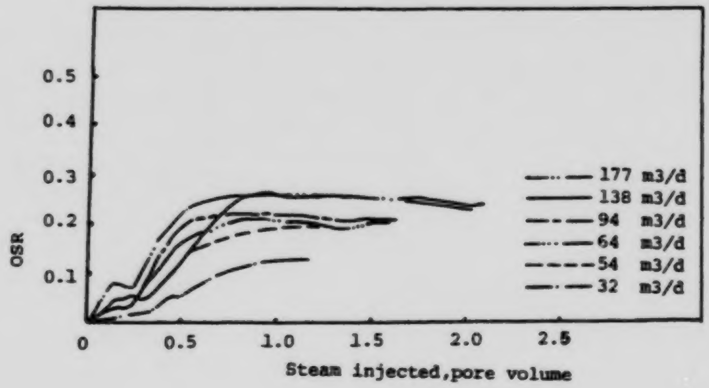
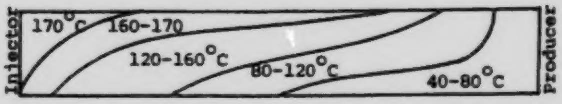
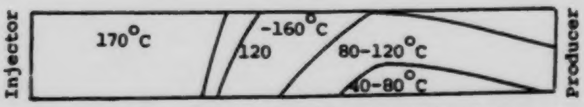


Figure 4.4
Vertical Temperature Distribution in the Formation at Varicus Injection Rate by Physical Model


Injector
170°C
160-170
120-160°C
80-120°C
40-80°C
Producer

(a.) Low injection rate (94 m3/d)


Injector
170°C
-160°C
120
80-120°C
40-80°C
Producer

(b.) High injection rate (177 m3/d)

Figure 4.5
Cumulative Oil Produced of Different Thick Formation with Well Spacing of 100 m.

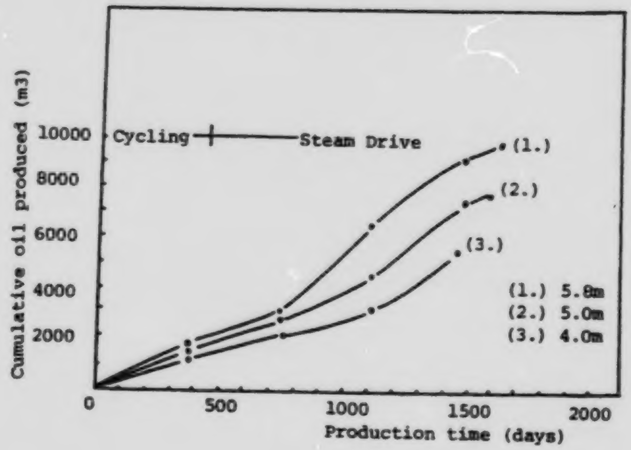


Figure 4.6
Cumulative Oil Produced of Different Thick Formation with Well Spacing of 140 m.

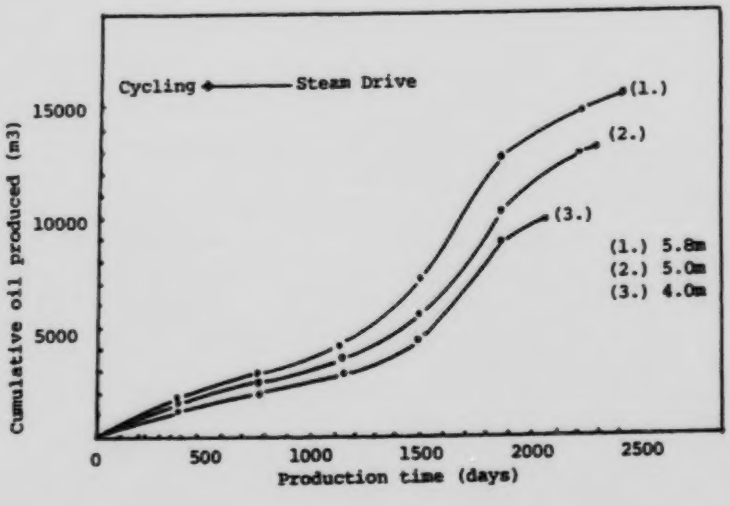


Figure 5.1
Relationship of Steam Injection and Oil Production vs. Operating Cost

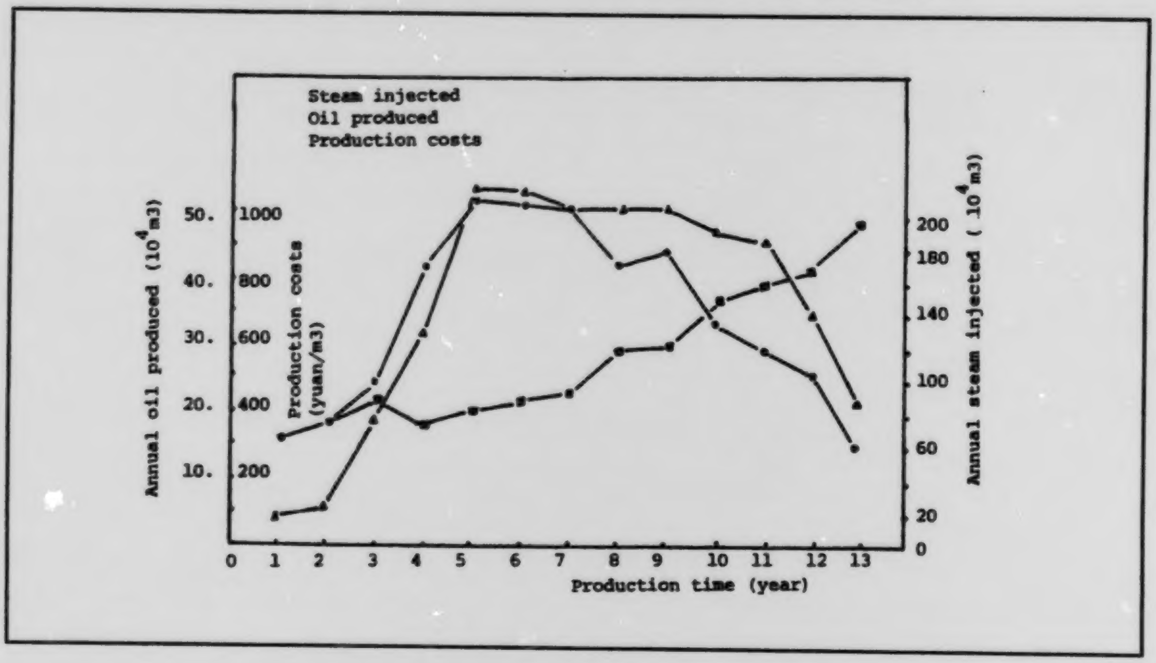
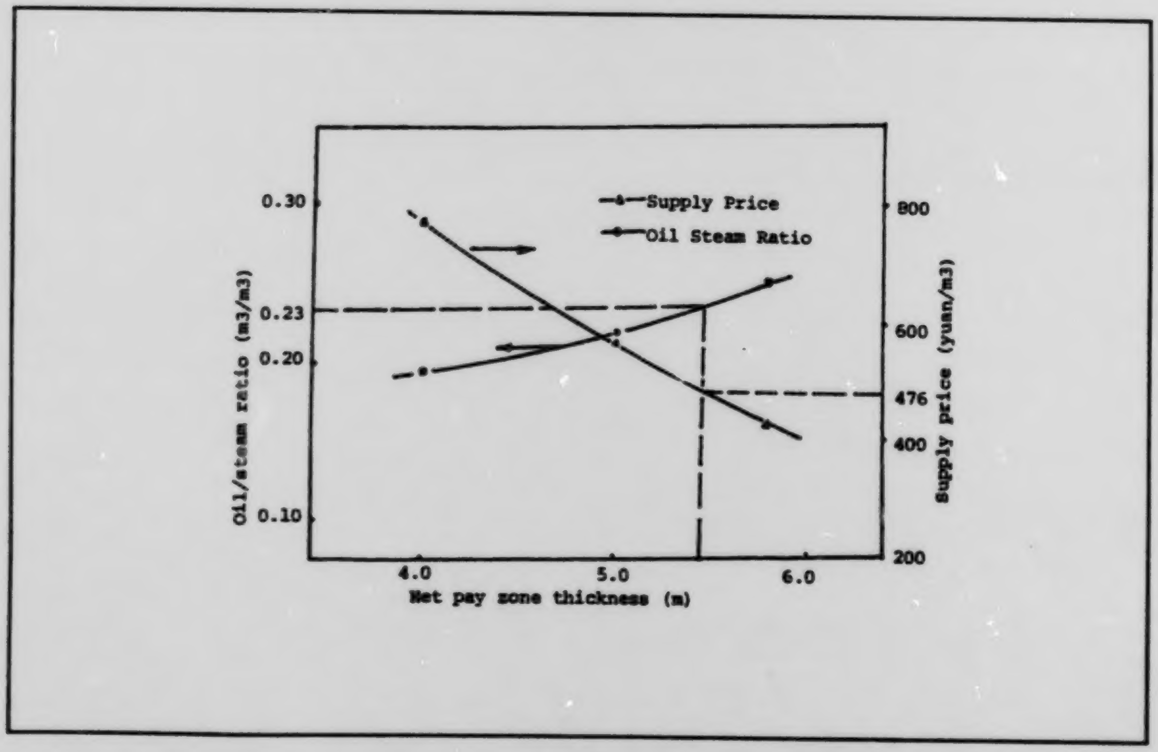


Figure 5.2
Effect of Formation Thickness on Economics



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PRIMARY SAND CONTROL TECHNOLOGY FOR LIAOHE HEAVY OILFIELD

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ABSTRACT

Among the three key technologies for heavy oil reservoir development: well completion, conventional production and thermal recovery technologies, well completion is considered to be the most important of all. Based on heavy oil characteristics, new drilling and well completion techniques have been used to prevent formation damage, to minimize sand production, to satisfy conventional oil production operating requirements and to meet high temperature requirement for thermal recovery operations

This article discusses the primary open hole gravel pack completion technique which was developed to meet the above requirements as well as to meet the objectives for high production and accelerating the development of Liaohe Oilfield. Improvements in gravel packing rate and quality are highlighted in the discussion.

INTRODUCTION

Considered to be an advanced well completion technology, open hole gravel packing technique using wire wrapped screen pipe is known for its effectiveness in term of complete coefficient, productivity, sand prevention and service factors. The technique is particularly effective in controlling sand production which is aggravated by steam injection. It ensures a sustained steady production from a high sand production reservoir by protecting the integrity of the oil bearing formation and by minimizing sand flows. Field testing of the primary sand control technique began at Liaohe heavy oilfield in 1986. A set of gravel packing operation parameters and guidelines were eventually developed after numerous improvements and adjustments were made to the testing program. Since the technique was widely applied beginning 1983, over 200 wells were completed with the technique, achieving an average packing efficiency of over 95%. Productivity has also noticeably been increased due to the implementation of the new technique.

BRIEF DESCRIPTION OF THE WELL COMPLETION TECHNIQUE

Well structure is usually consists of a 10 3/4 inch surface casing drilled to 150 meters and supported with ordinary cement. A 7 inch N80 steel casing is then lowered to the top of the reservoir through a 9 5/8 inch drilled hole and supported with a 75 °C thermal cement mixed with 30% 180 mesh quartz additive. A third drilling operation is subsequently proceeded into a sand control interval with a 6 inch drill bit drilling through a rubber retainer, cement plug and guide of the 7 inch casing after the well bore is cleansed with a 7 inch casing scraper, and residue and mud cake are flushed out with a highly charged completion fluid. A 5 inch wire-wrapped screen pipe is then lowered, packed outside with gravel and anchored with a lead-sealed adaptor at the top (Figure 1).

The sand packed string consists of a temporary inside string and a permanent outside sand control screen, the outside of which is packed with gravel. The inside string is only used for gravel packing and is removed after the operation. The interstice between the inside and the outside strings is kept as small as possible in order to increase flow resistance which forces sand slurry to flow to the lower part of the screen where flow resistance is smaller. This allows gravel to be packed from the bottom to the top and produces good quality packing. This is particularly important to deviated wells. According to field experiences from abroad and in-house, the ratio of screen inside diameter to outside diameter of the inner string should be maintained at 0.8.

The arrangement of the string is shown in Figure 2. A spring centralizer is installed at the collar of every second screen pipes. The inside and outside strings are connected by a nipple of a retrievable packer, on which a cross reverter nipple is connected (a double layer sand packing nipple). Two inverted cups installed on the nipple provide reversed sealing effect for a direct or a reverse sand packing circulating operations. The whole set of strings is ran as low to the bottom hole as possible by a 3 1/2 inch drill pipe. If a Christmas tree is installed on wellhead, hanger of the drill pipe is set at the four-way flanged valve.

After wellhead facilities are installed, sand packing is put into operation by mixing a sand carrying fluid with gravel on the surface and by pumping the slurry through the drill pipe into the annulus between the screen pipe and the underreamed hole through the inner pipe of the sand packing nipple. Because of the restriction of the sealed nipple, fluid can only flow down to the inner pipe through a signal screen, and then through a single valve into the annulus between drill pipe and the 7 inch casing. It is finally flows through the sand packing nipple and then out of the wellhead leaving gravel accumulating outside the signal screen pipe (Figure 3). When gravel exceeds a certain height of the sealed nipple, the flow of fluid is restricted causing pressure to increase to a certain value at which a pressure differential pin bolt breaks and allows the fluid into the screen pipe from the top of the sealed nipple through a newly formed circulating path between the pressure differential valve and the inner pipe string (Figure 3). The fluid flow continues until the outside of the screen pipe is fully filled with gravel.

On the completion of packing a predetermined amount of gravel, which is usually signalled by an increase of pump pressure, the well is backwashed to flushed out gravel from the drill pipe. After the backwash, the inner pipe string with the retrievable packer and the sand packing nipple connected to the inner pipe string are pulled out, leaving behind the screen pipe in the wellbore (Figure 1).

After pulling out the inner pipe string, the lead sealing operation is set in motion. The lead sealing nipple and the set-and-release tool are run down into the well bore by drill pipe and set on the landing nipple of the top of the screen pipe. With a down stroke striking and reversing action, the ring of the lead sealing nipple is forced to expand and prop between the 5 inch screen pipe and the 7 inch casing. After the lead sealing nipple is securely in place, a tubing is run down and the well- head facilities are installed. A light crude oil is then injected to complete the well.

PRIMARY SAND CONTROL COMPLETION PREVENTS RESERVOIR DAMAGE

Investigation of the mechanism of reservoir damage was conducted at Gaosheng oilfield which is one of the major heavy oil reservoir in Liaohe. Among the 18 wells drilled in the pilot area in 1979, 16 wells were completed with a 7 inch perforated casing specially designed for steam stimulation process. These wells were completed with a thermally stable cement mixed with 30% 180 mesh quartz powder before they were put into production in May, 1980. Only 3 wells produced 3-5 tons/day, with the remaining wells producing little or no oil at all. The low production was caused by the following reasons:

❑ 1. *Because specific gravity of the drilling fluid for the 12 wells was above 1.20 gm/cc and because the pay zone was soaked for 8 to 12 days, with some wells soaked as long as 43 days, bentonite from the drilling mud and water entered the reservoir and reacted with clay minerals in the reservoir. As a result of clay expansion, reservoir was plugged off. The situation is aggravated by the migration of sand which is sticked by the heavy oil and cannot be removed easily.*

❑ 2. *Steam injection requires the cemented interval be as long as 1,600 to 1,700 meters long. Because gravity of cement slurry was high, about 1.71 to 1.85 gm/cc, the hydrostatic pressure and pump pressure during the cement operation were also high, generally between 9.81 to 12.75 Mpa with some wells reaching as high as 17.65 Mpa. Consequently, the slurry invaded and plugged off the reservoir causing severe damage. Steam injectivity was poor and acid fracturing was ineffective in reducing the plugging problem.*

❑ 3. *In the process of perforating and down hole operations, well killing fluid of poor quality entered the perforating channels causing additional damages, which became much more severe if fluid was not discharged in time after perforation. If energized perforating charges were used, reservoir would be damaged because high temperature and pressure would cause films of metal charges to form around the perforations.*

EFFECTS OF RESERVOIR DAMAGE ON PRODUCTIVITY

The effect of well productivity by reservoir damage is proportional to damage radius with the most severe damage occurring within 0.5 meter around the well bore . Figure 4 shows that vertical sidewall damage was 18 cm when damage radius was 30 cm and that when permeability dropped from 493.46 μm^2 to 19.74 μm^2 and 4.93 μm^2, well productivity declined 24% and 7% respectively. Further increase in reservoir damage radius had little effect on the productivity, indicating that skin factor had a very significant effect on well productivity when the vertical sidewall damage was in the order of several centimetre deep.

Well productivity is directly related to the depth and the extent of the reservoir damage which is directly proportional to permeability,k,effective depth of reservoir h, and initial differential production pressure DP, but inversely proportional to oil viscosity μ, oil volumetric coefficient, b, logarithmic ratio of reservoir radius to bore hole radius R/r, and skin resistance coefficient S, as expressed by the following equation,

$$Q = 52.5 \, K \, h \, DP \, / \, (u \, b \, [Ln(R/r) + S]) \qquad \text{Eqn (1)}$$

Where the skin resistance coefficient S, is the sum of the resistance factors due to drilling damage Sd, perforation damage Sp and perforation density Sf, or

$$S = Sd + Sp + Sf \qquad \text{Eqn (2)}$$

and the resistance factor Sd due to drilling damage by mud and slurry is a function of reservoir permeability Kd and damage radius rd, as expressed by the following equation,

$$Sd = ((k/Kd)-1) \ln (rd/r) \qquad \text{Eqn (3)}$$

These relationships indicate that an improper use of drilling and completion methods could severely damage reservoir, particularly heavy oil reservoir.

Reservoir damage can be prevented using the primary open hole gravel packing method which consists of 3 operational steps: underreaming, screen pipe and gravel packing. The technique has the following advantages: 1) A technical casing is run and the well is cemented before drilling is proceeded into the reservoir which can easily be isolated from other layers of different pressures and from the overlying abnormal pressure. Reservoir damage can be avoided with an ordinary drilling mud and conventional cementing job, 2) Underreaming and sand packing operations are short (3-5 days); so is the soaking time of the reservoir in mud, 3) The completion technique uses drilling fluids of low gravity and high quality mud so that little or no damage is inflicted upon the reservoir, 4) By underreaming casing hole, area permeable to oil flow increases, 5) Gravel packing minimizes sand production and improves well complete factors and 6) No damage is caused by perforation.

In order to prevent mud damage to reservoirs, many tests had been conducted in recent years and a series of six mud types were developed such as PAN low solid mud, CPC bentonite mud, no solid brine mud and so on (Table 1). After further verification in laboratory and at fields, the CAC no bentonite mud was used as a drilling fluid in the operations of the third drilling stage into the reservoir, of underreaming and sand packing in the primary sand control wells. The drilling fluid is made of a gelled mixtures of macromolecule polymer CMC and aluminium salt KAL $(SO_4)_2$,with 250 mesh limestone powder for gravity adjustment. The salient features of the drilling fluid are: low gravity (1.02-1.08 gm/cc), low water loss (3-14 ml under median pressure), thin mud cake (0.5 mm), low shearing force, good sand removal capability and low sand content, thermally stable and good rheological behavior (0.55-0.75 n value and 0.7-1.5 k value).

Using the above drilling mud together with the mud clarifying process, reservoir damage had been minimized or eliminated with virtually no effect on the reservoir permeability. By enlarging the permeable area with underreaming and by sand packing with screen pipe, resistance factors in the area around well bore was reduced noticeably, resulting in high fluid flow from the reservoir to the well bore Production index doubled with the open hole gravel packing technique as compared with the perforating completion technique.

A group of primary sand control wells were put into production at Gaosheng oil field in 1986. Nearly half of the wells were newly drilled at the edge of the reservoir and near the fault. The pay zone of the wells were thin, with poor physical properties and low permeability. As reservoir pressure dropped, oil/gas ratio increased. Although the conditions of the new wells were poor, they were able to produce more than 10 tons/day as a result of using CAC light weight high quality drilling mud and primary sand control technique (Table 2).

Quality Control of the Gravel Pack Used in the third drilling operations before setting the screen pipe, high quality completion fluid is fundamentally essential for maintaining gravel packing efficiency. It also affects reservoir damage, drilling depth and underreaming process. It is therefore essential that proper mud type and formulation be used and precise formation on pressure factor be available so that a balanced pressure drilling operation can be effectively executed. To minimize reservoir damage, mud gravity should be kept as low as permissible by formation pressure, and drilling fluid should contain less than 0.2% sand and particularly no bentonite at all. Also, well bore must be cleaned during screen pipe and gravel packing operations in order to avoid the screen pipe from plugging. At last but not the least, clean wash fluid is used before the third drilling operation into the reservoir. It is essential that drilling mud equipment should be cleaned thoroughly and the clarifying equipment must be ready for the operation. We had learned hard lessons of poor wash fluid during the early stage of production.

Another factors of fundamentally important for attaining high gravel packing efficiency is large well bores with regular sidewall, which is achieved by underreaming operation after the 6 inch bore hole is drilled. Reaming is done with a sidewall platform and three tooth wheel arms of a reaming bit. To achieve an effective reaming operation, drilling speed and penetration rate must be kept slow and steady to avoid an irregular and spiral bore hole. Also, reaming parameters such as rotary speed, discharge rate and pump pressure must be controlled within specifications. Reaming should be completed with a single operation or else subsequent repair job will be difficult and costly. Only with bore hole large enough that the exterior of the screen pipe can be packed with thicker gravel layer so that sand production can be effectively controlled. The regularity of bore hole is important to gravel packing operation because it can minimize the formation of sand bridge which affects gravel packing efficiency.

Another effective measure in improving gravel packing efficiency is to pack the gravel in two stages using clean fresh water for preflush and displacing fluid. The advantages are: 1) It shortens actual sand packing time and minimizes the formation of sand bridge, 2) The displacement period after the first packing stage can be as long as an hour. The wash water dilutes mortar and cleans gravel, resulting in better settling and packing of gravel, and 3) Wash water also cleans the screen pipe, sidewall and the packed gravel. It provides favourable conditions for the second stage of the packing operation. The technique is particularly effective for packing a long interval.

Gravel packing efficiency can also be improved with a lower discharge rate of displacement fluid. With a sand carrying fluid of proper viscosity and sand ratio, sand bridge problem can be kept to a minimum. By recycle of the sand carrying fluid, operation costs are reduced. Discharge rate of the fluid is usually kept smaller than the free falling velocity of mortar outside the screen pipe to allow packing of gravel from the bottom to the top. A CA sand carrying fluid was selected for our operations because of its chemical compatibility with the drilling fluid used in the third drilling stage. With its viscosity between 100 and 150 Pa.s, sand ratio between 60 and 80% and discharge rage between 150 and 200 liter/minute, the CA sand carrying fluid has been performing quite well for the gravel packing operation.

Good sand carrying fluid should have the following characteristics: 1) it is viscous, stable and capable of carrying sand, 2) strong buoyancy to keep gravel from settling too fast so as to cause pump plugging and impede fluid circulation, 3) no solid, low water loss and causes no reservoir damage, 4) capable of viscosity reduction with chemical additive and temperature effect, 5) able to provide sufficient gravity to balance off the reservoir pressure and prevent heavy oil from flowing into the bore hole, and 6) it is readily available with low cost, easy to formulate and apply at the fields.

The type of gravel and openings of screen pipe should be properly selected in order that the objectives of controlling sand and maintaining permeability can be achieved. The main guideline for selecting gravel are based on its physical and chemical properties and the diameter and roundness of grains. For a heterogeneous formation sand, gravel size should be 5 to 7 times the median grain size of formation sand; the roundness should be 0.7. Gravel size should change little under 21 days of high temperature test, with weight loss no more than 3%. The gravel should possesses yield strength to withstand 20 MPa pressure, with gravel crushing rate less than 18%.

Screen pipe opening is selected based on the median grain size of formation sand and gravel size. Opening is usually kept 2/5 to 3/5 of the smallest gravel size. Since gravel size used in Liaohe oil field was 0.5 to 0.8 mm and 0.8 to 1.2 mm, the openings of 0.3 mm and 0.4 mm were selected.

By installing an oscillator on the packing pipe which oscillators the screen pipe continuously during the packing operation, gravel packing efficiency can be improved with the oscillating packing method. The technique prevents gravel from sticking to the upper part of the screen pipe and keeps the formation of sand bridge to a minimum.

CONCLUSIONS

The primary sand control method prevents reservoir damage and significantly increases productivity as observed from the wells that drilled with the technique in May 1983. Production from these well over a period of more than two years indicates that reservoir damage was greatly reduced. The damages at Well 3-5-52 and Well 3-3-082 had almost been eliminated, with the highest production from these wells reaching 42.2 and 63 tons/day respectively. The average daily production from the primary sand control wells was about 20 tons.

The primary sand control completion by open hole gravel packing is suit- able for heavy oil reservoir of great depth, high formation pressure, and severe sand production. It is a good method for increasing production rate and accelerating oil field development.

The primary sand control method can meet the requirements of thermal recovery processes. Most of the primary sand control wells achieved stable production with no sand problem since they were put into production in 1982. 22 of these well experienced temperature as high as 300 to 350 °C and pressure from 9.81 to 15.98 MPa during the steam stimulation operations with little effect on their performances.

The technique is to be improved further for total elimination of reservoir damage, for wider applications, longer packing intervals and preventing sand flows in separate layers.

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- 2) Liu W.Z., "Development and Research of Completion Technology in HeavyOil Fields"
- 3) Liu W.Z., "Technical Research Report on Thermal Production in Heavy Oil Wells from Abroad"
- 4) Reports Of the Eleventh World Oil Conference

Table 1
The Mud for Main Hole and Under-Reaming

Table #1

THE MUD FOR MAIN HOLE AND UNDER-REAMING

ITEM	TYPE	COMPOSITION	SPECIFIC GRAVITY	FUNNEL VISCOSITY (sec)	WATER LOSS (cc)	MUD CAKE (mm)	SAND CONTENT (%)	SHEARING FORCE	pH	NUMBER OF TIMES USED
1	PAM Low Solid	PAM, CMC, PAN, Bentonite	1.06	35-60	5	1	0.6	9-10	8	2
2	PAM Low Solid	PAN, CPA, Na2CO3, Bentonite	1.05-1.08	35-55	5	1	0.4	0-16	9.5	3
3	PAM, PAN Low Solid	PAM, PAN, Na2CO3, Bentonite	1.04-1.08	40-55	5	1	0.4	0-0	9	4
4	CPC Non-bentonitic	CMC, PAM, CaCO3	1.02-1.08	80	4	0.5	0.2	0-0	9	2
5	CAC Non-bentonitic	CMC, KAl(SO4)2, CaCO3	1.02-1.08	80-120	3-5	Trace-0.5	0-0.2	0-0	7-9	Promoting
6	No Solid Salt Water	NaCl, KCl, CMC, CPA	1.07-1.10	129-135	5.5	Trace	0	0-0	9	2

Table 2
Statistical Oil Production on Primary Sand Control of Completion Wells

Table #2

STATISTICAL OIL PRODUCTION ON PRIMARY SAND CONTROL
OF COMPLETION WELLS

YEAR	SAND MEMBER									TOTAL		
	No. 5			No. 6			No. 7					
	No. of Wells	Average Single Well Daily Oil Production (Ton)		No. of Wells	Average Single Well Daily Oil Production (Ton)		No. of Wells	Average Single Well Daily Oil Production (Ton)		No. of Wells	Production by Year End (Ton)	Average Daily Oil Production (Ton)
		Beginning of Year	End of Year		Beginning of Year	End of Year		Beginning of Year	End of Year			
1983	2	20.1	22.8	6	22.2	23.2	—	—	—	8	189	23.6
1984	19	13.3	13.4	30	25.3	25.4	4	16.4	14.6	53	1075	20.3
1985	11	16.1	12.1	28	30.7	24.4	9	26.9	20.7	48	1002	20.9
1986	29	16.0	9.7	32	19.8	16.7	15	23.4	16.2	76	1057	13.9

REMARK : In 1980, there were 16 wells in the three sand members and the conventional completion method was used. Only three of the 16 wells produced 3-5 Tons of crude oil per day.

Figure 1
Schematics of primary Sand Control Well

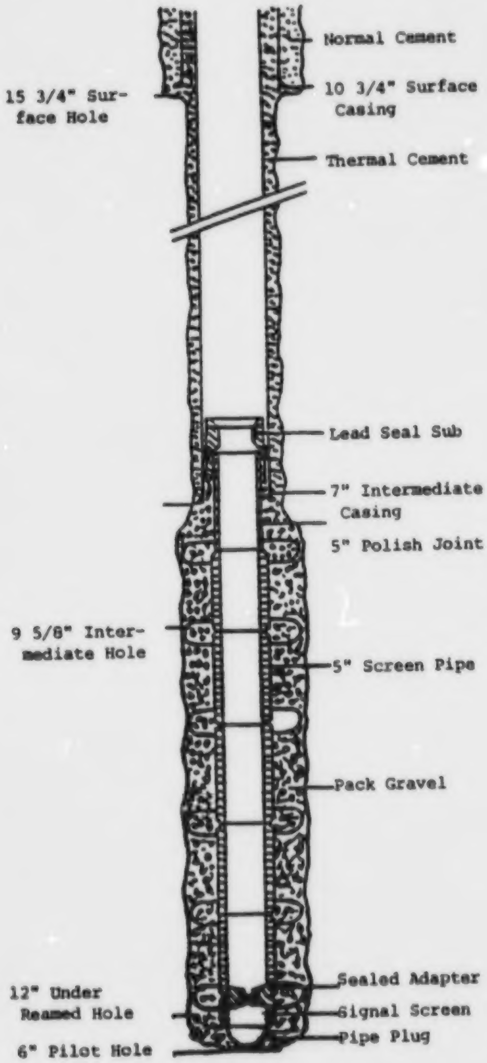

Normal Cement
15 3/4" Surface Hole
10 3/4" Surface Casing
Thermal Cement
Lead Seal Sub
7" Intermediate Casing
5" Polish Joint
9 5/8" Intermediate Hole
5" Screen Pipe
Pack Gravel
12" Under Reamed Hole
Sealed Adapter
Signal Screen
Pipe Plug
6" Pilot Hole

Figure 2
Screen Pipe Liner and Running Tool for Gravel Packing

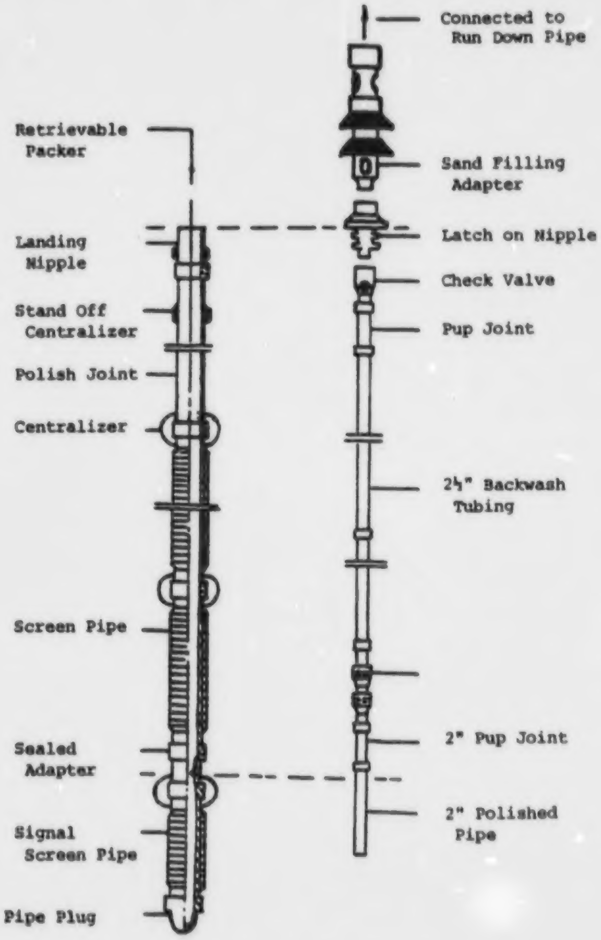

Connected to Run Down Pipe
Retrievable Packer
Sand Filling Adapter
Landing Nipple
Latch on Nipple
Check Valve
Stand Off Centralizer
Pup Joint
Polish Joint
Centralizer
2½" Backwash Tubing
Screen Pipe
2" Pup Joint
Sealed Adapter
2" Polished Pipe
Signal Screen Pipe
Pipe Plug

Figure 3
Gravel Pack Assembly Rig-Up and its Function

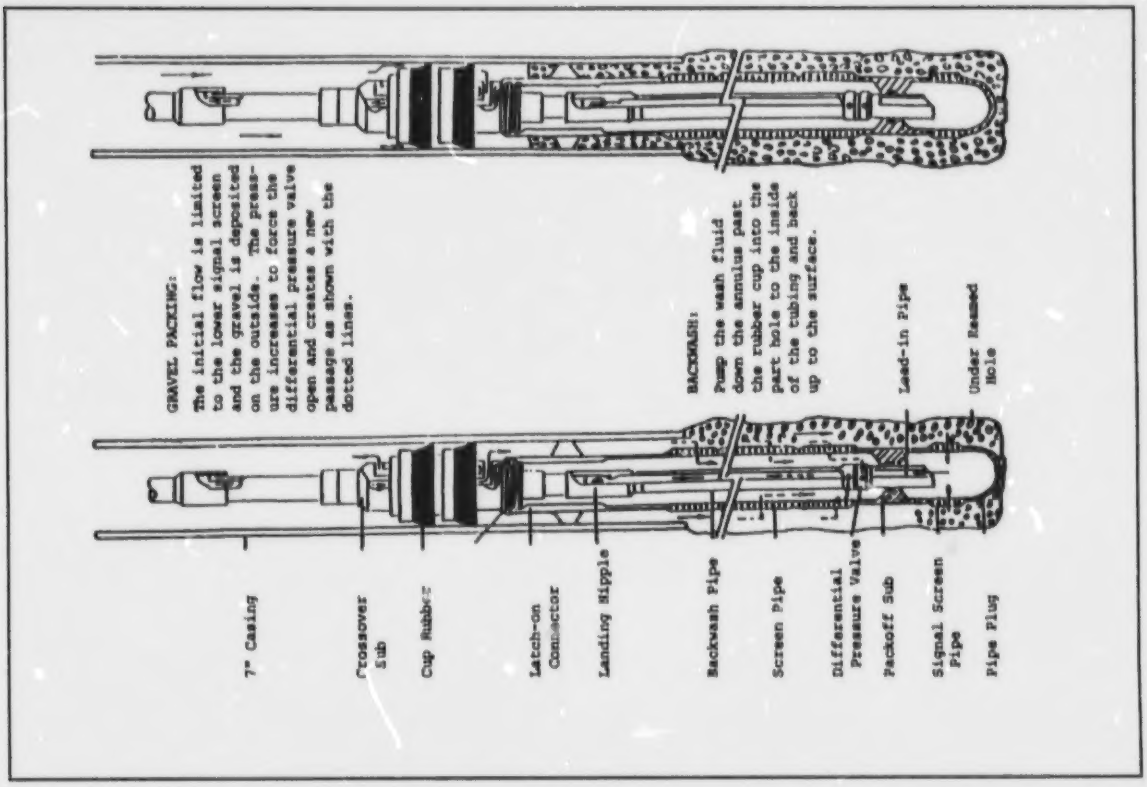
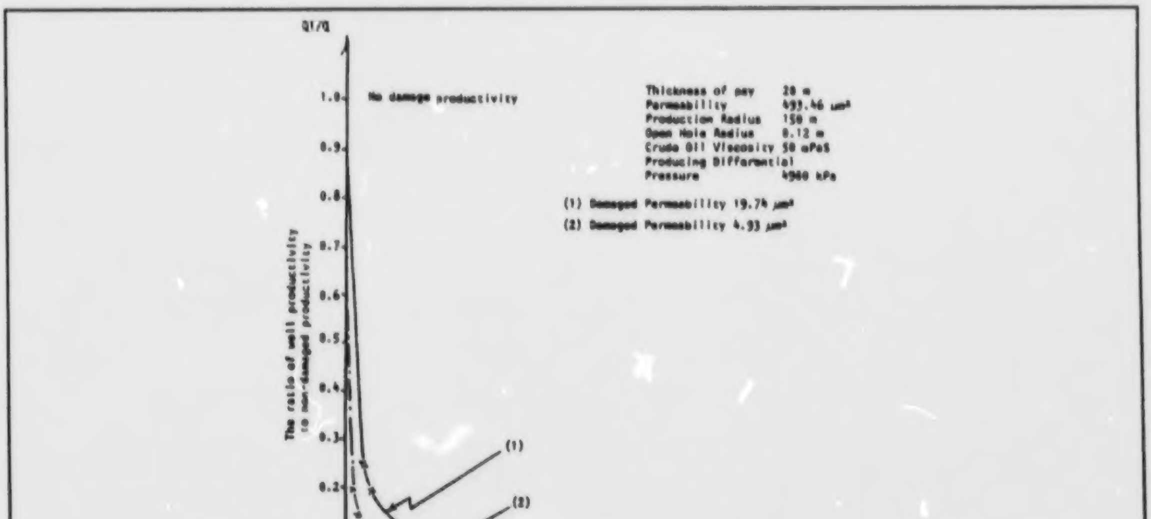

GRAVEL PACKING:
The initial flow is limited to the lower signal screen and the gravel is deposited on the outside. The pressure increases to force the differential pressure valve open and creates a new passage as shown with the dotted lines.
BACKWASH:
Pump the wash fluid down the annulus past the rubber cup into the part hole to the inside of the tubing and back up to the surface.
7" Casing
Crossover Sub
Cup Rubber
Latch-on Connector
Landing Nipple
Backwash Pipe
Screen Pipe
Differential Pressure Valve
Packoff Sub
Lead-in Pipe
Signal Screen Pipe
Under Reamed Hole
Pipe Plug

Figure 4
The Relationship of Productivity and Formation Damage



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QUARTZ SAND AS A GRAVEL PACKING MATERIAL IN HUFF AND PUFF WELLS

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ABSTRACT

Sand production is one of major production problems in huff and puff wells. This article focuses on experiment comparing the pH of liquid samples taken from various points of the steam injection and generating system under different pressure conditions with pH of steam condensate downhole. This pH determines the suitability of quartz sand as gravel packing material. The field data of using quartz sand as gravel packing material in Sheng-Li heavy oil reservoir is presented and discussed.

INTRODUCTION

The Shanjiashi heavy oil reservoir located in the Sheng-Li field is about 1100m deep and consists of unconsolidated sandstone. As a result, sand production is a major production problem. The in-situ viscosity is greater than 100,000 MPa.s. Such high viscosity dictates the use of steam injection as the only proven production method for oil recovery. The steam temperature must be 350° C at injection.

Gravel packing with a wire wrap screen has been proven to be the most effective sand control method in a huff and puff heavy oil producer (1). Hence, a series of downhole gravel packing tools and screen were developed based on local reservoir conditions. Concurrently, the effectiveness of quartz sand as a gravel packing material was evaluated in a huff and puff well with various pH liquids.

As a result, a new sand control technology based on reservoir and operating conditions was established for all huff and puff wells in the Shanjiashi reservoir. This new sand control procedure has been used in 43 wells, 32 of which have been put on production. Of these 32 wells, 9 of them are in their second huff and puff cycle and 4 in their third. Most of the wells do not experience any production difficulties. Cumulative production is 43,000 tonnes and the sand content is less than 0.01%.

This paper details the determination of the pH level in a huff and puff well and the effectiveness of quartz sand as gravel packing material.

GRAVEL PACKING MATERIAL IN HUFF AND PUFF WELLS

Traditionally, the pH value of the liquid effluent from a boiler is measured from a sample that has been depressurized and cooled to the ambient conditions. The pH value has been measured as high as 10-12.4 (1,2-5), which is an increase of 3-4 over the softened boiler feed water (Table 1). This increase is due to the decomposition of [HCO_3-] in the boiler feed water. At high pressures and at low temperatures, [HCO_3-] will decompose into gaseous CO_2 which escapes into the atmosphere, with the associated basic ions OH-or CO_3^{-2} remaining in the liquid phase. The chemical reaction is as follows:

$$HCO_3^- \text{ (low concentration)} \leftrightarrow CO_2 \text{ (gas)} + OH^- \qquad (1)$$

and

$$2HCO_3^- \text{ (high concentration)} \leftrightarrow CO_2 \text{ (gas)} + CO_3^{-2} + H_2O \qquad (2)$$

Under high temperatures and low pressures, the equilibrium moves toward the right hand side. It has been found that temperature and the pH of the solution are the major factors affecting the dissolution of SiO_2 (2,6,7). Reed (3) found that at 260° C and a pH of the solution greater than 11.3, the quartz sand and the formation sand will dissolve significantly, the SiO_2 dissolves at a rate of 3.6 Kg per cubic metre of solution. It has been suggested that since the pH of the boiler effluent is high, the pH of the liquid in the steam injectors must also be high, and hence quartz sand cannot be used for gravel packing (1,2,5,8,9). Instead, alkaline resistant materials such as resin coated quartz sand, sintered bauxite, ceramic beads with high aluminum content or carborundum should be used (1,8,9). It has also been suggested that either ammonium salts (e.g. NH_4NO_3) be added to the boiler feed water (5), or that boiler feed water of a suitable quality be pretreated with HCl (2) to reduce the pH of the boiler effluent.

There is no established correlation between the pH values in the depressurized boiler effluent and that of the wellbore fluid. Since $[HCO_3\text{-}]$ in the boiler effluent decomposes readily at high temperature and low pressure, this process will increase the pH of the effluent. A high pH value for the depressurized boiler effluent does not necessarily mean a high pH fluid in the wellbore. To date, no direct pH measurement of the fluid in the wellbore has been reported. If there was such a correlation, with high temperature and high pH fluid existing within the wellbore, both the quartz sand and the formation sand would dissolve, causing severe sloughing of near wellbore formation and severe deformation of production casing. Eventually, the formation wouid collapse and renders the huff and puff recovery scheme uneconomical. In reality, the above events do not occur, the huff and puff recovery scheme has been used extensively and very successful economically (10-13).

Accordingly, laboratory simulation and field sampling was undertaken to determine the pH value of the wet steam in the wellbore,with the intention of determining the effectiveness of quartz sand as a gravel packing material for huff and puff well.

1. Laboratory Simulation.

1.1 Measuring The pH of Steam at Low Pressure.

Steam Sampling Procedures

Add 500 ml of test fluid into each of the two high pressure steam generators (Figure.(1). 100 ml of fluid from each of these steam generators is removed and labeled as test fluid A. The fluid in the steam generators is heated and maintained at 260° C and 8-10 MPa for 30 minutes. A steam vapour sample is taken from steam generator #1 through valve 4-1 as shown in Figure 1. The condensed steam vapour sample is labelled "vapour condensate C". Steam generator #1 is then cooled down and the remaining fluid is labelled "vapour sample residue D". A steam liquid sample is taken from steam generator #2 through valve 4-3 as shown in Figure 1. The steam liquid sample is then cooled down and labelled "liquid condensate E" and the remaining fluid in cool down steam generator #2 is labelled "liquid sample residue F". These five samples are then analyzed for pH, and concentration of $[HCO_3\text{-}]$, $[CO_3\text{-}^{2}]$ and $[OH^-]$.

Effect of Test Fluids on The pH of Steam

☐ *a. Sodium Bicarbonate Solution*

Sodium Bicarbonate is added to distilled water and used as the test fluid for the steam generators. The concentrations of $[HCO_3^-]$ in the water used for these tests are 9.3, 50.8, 320.0, 1040, 2200 and 9100 mg/l. Each test fluid is simultaneously added to these two steam generators and then began a series of tests. The results are shown in Figures 2,3 and 4.

From Figure 2, it can be seen that

i) The pH of the steam vapour sample, vapour condensate C, is the lowest (6.2 - 4.4) while that of the vapour sample residue D is the highest. With the concentration of $[HCO_3^-]$ in the test fluid less than 1000 mg/l, the pH value of vapour sample residue D increases with the increase of $[HCO_3^-]$, otherwise, the pH value decreases with the increase of $[HCO_3^-]$. The pH value of steam generator fluid D increases by 1.7 - 3.6 over test fluid A.

ii) The pH of liquid condensate E shows the same trends as that of steam generating fluid D. It increases by a value of 1.5-2.0 over that of test fluid A. Liquid sample residue F maintains more or less the same pH value as test fluid A.

It can be concluded that at any concentrations of $[HCO_3^-]$, the pH value of the five different samples is arranged in the following order. Vapour sample residue D (8.2-11.8-10.6) liquid condensate E (8.0-10.4-9.2) test fluid A (6.6-8.0) = steam generator fluid F (6.5-8.0) vapour condensate C (6.2-4.4). The pH value depends on the concentration of $[HCO_3^-]$ in the test fluid and the sampling procedures.

The following conclusions can be reached from data in Figures 3 and 4.

a) Within the range of concentration of $[HCO_3^-]$ used in the test fluid, the concentration of $[HCO_3^-]$ and $[CO_3^{-2}]$ ions in test fluid A and liquid sample residue F are nearly identical, resulting in similar pH for both fluids.

b) In taking a sample of liquid condensate E, the liquid phase of the wet steam is cooled in the condenser under atmospheric pressure. Part of the $[HCO_3^-]$ in liquid decomposes, resulting in its

$[HCO_3^-]$ concentration being lower than that of test fluid A and liquid sample residue F (Figure 3.), and its $[CO_3^{-2}]$ concentration being higher than that of the same two fluids (Figure 4.). Hence the pH value of liquid condensate E increases. Both test fluid A and liquid sample residue F have similar concentrations of $[HCO_3^-]$ and $[CO_3^{-2}]$ ions suggesting that the $[HCO_3^-]$ of the wet steam does not decompose significantly in a high temperature and high pressure environment.

c). For any test fluid A, vapour condensate C has the lowest pH, being acidic. While taking the vapour condensate C sample, the sampling valve 4-1 (Figure 1.) is opened slightly, causing $[HCO_3^-]$ in the steam generator to decompose, and part of the gaseous CO_2 escapes with the steam vapour and condensed into vapour condensate C sample. The associated $[OH^-]$ and $[CO_3^{-2}]$ ions remain in the liquid phase and become vapour sample residue D. Hence, the $[HCO_3^-]$ concentration in vapour sample residue D is lower than that of liquid condensate E and the $[CO3^{-2}]$ concentration is higher than that of test fluid A and liquid sample residue F. With $[HCO_3^-]$ concentration less than 1000 mg/l in the test fluid, the $[HCO_3^-]$ ions in vapour sample residue D will completely decompose into $[OH^-]$, resulting in the $[HCO_3^-]$ concentration being zero in vapour sample residue D. Hence vapour sample residue D has the highest pH value. With the $[HCO_3^-]$ concentration greater than 1000 mg/l, the $[HCO_3^-]$ in the vapour sample residue D cannot completely decompose, hence the fluid's pH will not increase as much. Liquid condensate E shows the same trend, with its $[HCO3-]$ decomposing in a similar fashion but to a lesser degree as vapour sample residue D.

By passing the steam vapour through a transparent and fully saturated calcium hydroxide solution, white precipitate will form in the solution. This white precipitate will disappear with the addition of a dilute HCl solution. This suggests that the steam vapour contains CO_2, causing the vapour condensate C to be slightly acidic.

b. Sodium Hydroxide Solution.

Test fluids are prepared by adding 30, 80 and 500 mg/l of NaOH to distilled water. The same steam sampling procedures as previously outlined are followed and the results are shown in Figures 5 and 6.

From Figure 5, it can be seen that for any concentration of NaOH, the pH values of steam condensate D, liquid condensate E, steam generator fluid F and test fluid A are very close. This is a fundamental difference from the results obtained by using sodium bicarbonate solution. If the test fluid A lacks $[HCO_3^-]$, sampling procedures will not cause any $[HCO_3^-]$ decomposition, resulting in the concentrations of $[OH^-]$ and $[CO_3^{-2}]$ ions being the same in liquid condensate E, liquid sample residue F and test fluid A, with vapour condensate C lacking CO_2. Hence, the pH of vapour condensate C is higher than that obtained by adding sodium bicarbonate to the test fluid (Figures 8 and 5). For vapour sample residue D, due to its large volumetric reduction, the concentration of $[OH^-]$ and $[CO_3^{-2}]$ is slightly higher than that of test fluid A, liquid condensate E and liquid sample residue F (Figure 6).

c. Softened Boiler Feed Water

Softened boiler feed water is used as a test fluid using the same testing procedures as above with the exception of temperature. The results are shown in Figures 7, 8 and 9. The overall pH trends are the same as those obtained by using sodium bicarbonate solutions.

(i) The pH value of liquid condensate E is significantly higher than that of liquid sample residue F and test fluid A. The $[HCO_3-]$ and $[CO_3-^2]$ concentrations are the same in liquid sample residue F and test fluid A. The $[HCO_3^-]$ in liquid condensate E has completely decomposed into $[OH^-]$ and $[CO_3^{-2}]$ and hence increasing its pH.

(ii) The pH trend of the vapour condensate C and steam generator fluid D are the same as that shown by using distilled water containing sodium bicarbonate as a test fluid.

(iii) The sequence of the pH values are as follows: Vapour sample residue D (11.2-11.9) liquid condensate E (10.2- 10.8) test fluid A (7.9-8.2) = liquid sample residue F (7.8-8.1) vapour condensate C (4.6-5.8). The degree of $[HCO_3^-]$ decomposition depends on the sampling procedures and is independent of the concentration of other ions (e.g. $[Cl^-]$, $[Na^+]$) in the softened water and the change in temperature.

■ 1.2 Measuring The pH of Steam At High Pressure.

The experimental setup is shown in Figure 10. As shown in Figure 10, 600 ml of softened boiler feed water is poured into the high pressure steam generator 1. 100 ml of which is removed and labelled as test fluid A. The high pressure steam generator is heated to a preset temperature and maintained at that temperature for 30 minutes. The high pressure liquid flow through needle valve 5 and down the tubing 7, to a kerosene filled high pressure container 13, with the back pressure in the container being controlled by needle valve 9. After 100 ml of kerosene has been collected at 11, the high pressure container 13 and steam generator 1 are cooled down. The liquid condensate in the high pressure container is labelled E and the fluid in the steam generator is labelled residue liquid F. The pH of these fluids are measured and the results are shown in Table 2.

From Table 2, it can be seen that the $[HCO_3^-]$ concentration in liquid condensate F decreases with a decrease of the back pressure in the high pressure container. This is due to an increase in the rate of decomposition of $[HCO_3^-]$ with a decrease of the steam generator back pressure. Therefore, the $[HCO_3^-]$ in the liquid phase does not decompose significantly in a closed high temperature and high pressure system.

1.3 Dissolution of Gravel Packing Material in The High Pressure Steam Generator.

Three kinds of gravel packing materials are tested. Six copper wire mesh bags each containing 10.0 g (W_1) of a gravel packing material along with 400 ml of test fluid are put into the high pressure steam generator. The steam generator is heated and maintained at a constant pressure and temperature for several days. Afterwards, the steam generator is cooled down and each type of gravel packing material are cleaned, dried, and weighed (W_2) to determine the gravel dissolubility.

The gravel dissolubility I is expressed as

$$I = (W_1 - W_2)*100\% / W_1$$

Where:

W_1 is the weight of gravel packing material prior to testing and

W_2 is the weight of gravel packing material after testing.

The pH values of the test fluids were also measured before and after the test. The test results are shown in Table 3.

From Table 3 it can be concluded that

i) With distilled water and softened water as the test fluids, quartz sand does not dissolve under high pressures and temperatures.

ii) The gravel dissolubility increases with an increase of the test temperature, the initial pH value of the test fluids, and the constant temperature test duration. Quartz sand dissolves significantly in test fluid with an initial pH greater than 11.0, ceramic beads do not, increasing in weight instead.

2 FIELD TEST

2.1 Measurement of Gravel Dissolution in The Steam Injector.

Replace the bottom joint of the production string with the tubing joint containing the cooper wire mesh bags with gravel packing materials (Figure 11). Wet steam is injected into this huff and puff producer and then the well is put into production. The steam injection parameters are shown in Table 4.

After a predetermined period (approximate 2 weeks), the tubing is pulled, gravel packing materials retrieved, cleaned, dried and weighed. The results are shown in Table 5.

Table 5 shows that after one huff and puff production cycle, pure quartz sand shows little change in grain size and weight, Lan Chow sand (Sand B) shows greater change due to higher impurities.The ceramic beads are very lumpy and mixed with formation materials.

2.2 Measuring The pH of Steam Condensate in an Steam Injector.

Model SLQ-I wet steam sampler is run downhole for 20 minutes during the steam injection phase. At the same time, fluid samples of the boiler feed water and boiler effluent at low back pressure are taken. The wet steam condensate is retrieved from the sampler after it is cooled down. These samples were analyzed and the results are shown in Table 6.

Table 6 shows that the pH of the bottomhole liquid is similar to that of the boiler feed water, and is significantly lower than that of the boiler liquid effluent taken at low pressure. These results suggest that the pH in the wellbore of a steam injector is not very alkaline.

2.3 Quartz Sand as a Gravel Packing Material in Huff and Puff Wells.

Quartz sand has been used successfully as gravel packing materials in huff and puff producers at the Cats Valley field in California, the Gao-Sheng reservoir of the Liao-He field and the Shanjiashi reservoir of the Sheng-Li field in China. At Shanjiashi, the injection steam temperature ranges from 310 to 370 degrees C and the pH of the boiler liquid effluent sample taken at low pressure ranges from 11.4 to 11.8. During each huff and puff cycle, steam equivalent to 3000 tonnes of water was injected into a producer, with the production being sand free (Table 7).

3 DISCUSSION

☐ *i) Why does the pH of the boiler liquid effluent sample taken at low pressure increase 3 to 4 units over that of the boiler feed water?*

The flow diagrams for sampling boiler liquid effluent are shown in Figures 12 and 13. The softened boiler feed water contains about 300 mg/l of $[HCO_3^-]$ (Table 1). As shown in Figure 12, the wet steam from the boiler flows through the steam/liquid separator (4 in Fig. 12) and the liquid is piped to the intermediate condenser (9 in Fig. 12) where it is cooled. The liquid then flows through a pressure reduction valve (10 in Fig.12) and is then collected as boiler liquid effluent under atmospheric pressure.

The increase in boiler liquid effluent pH is due to the decomposition of $[HCO_3^-]$ in the liquid phase as shown in equations (1) and (2). At atmospheric pressure, the reaction moves to the right. The $[HCO_3^-]$ in the hot liquid decomposes into gaseous CO_2, $[OH^-]$ and $[CO_3^{-2}]$· CO^2 escapes to the atmosphere, while the $[OH^-]$ and $[CO_3^{-2}]$ remain in the liquid. This reaction increases the pH of the boiler liquid effluent. Table 1 shows that there are 301 to 409 mg/l of $[HCO_3^-]$ and zero mg/l of $[OH^-]$ in the boiler feed water, but there is zero mg/l of $[HCO_3^-]$,and 177 to 297 mg/l of $[OH^-]$ in the boiler liquid effluent. $[CO_3^{-2}]$ also increases in the boiler liquid effluent. This increase is due to a reaction between $[OH^-]$ and the residue $[HCO_3^-]$ in the boiler liquid effluent.

That is $[OH^-] + [HCO_3^-] \rightarrow [CO_3^{-2}] + H_2O$. (3)

If $[HCO_3-]$ in the liquid phase has completely decomposed, the theoretical pH value of the liquid can be calculated under the following assumptions.

(a) The $[HCO_3^-]$ concentration in the liquid is less than 1000 mg/l, and higher than the concentration of other ions. $[HCO_3^-]$ can only decompose into $[OH^-]$ and CO_2.

(b) All produced CO_2 escapes quickly from the liquid after decomposition.

(c) The pH of the boiler feed water is 8, and the change in liquid volume due to vaporization is less than 80% of the initial liquid volume

From equation (1)

$$
\begin{array}{ccc}
[HCO_3^-] \rightarrow & CO_2\,(gas) + & [OH^-] \\
61*103 \text{ mg/l} & & 17*103 \text{ mg/l} \\
A & & X
\end{array}
$$

Where:

A is the $[HCO_3^-]$ concentration in boiler feed water, and X is the $[OH^-]$ concentration of the boiler liquid effluent sampled at atmospheric pressure.

$X = 17 * A / 61$

From this value of X, the pH of the boiler liquid effluent can be calculated. The results are shown in Table 8.

Table 1 shows that the boiler feed water for the three reservoirs ranges from 311 to 406 mg/l. Based on Table 8, the pH of the boiler liquid effluent ranges from 11 to 12. This value is very consistent with the measured pH from these three fields (11.5 for Gao-Sheng, 11.3 for Shanjiashi, and 12.4 for field data from the U.S.A.)

When $[HCO_3^-]$ concentration in the boiler feed water ranges from 61 to 610 mg/l, the pH of the correspondent boiler liquid effluent ranges from 11 to 12 and is 3 to 4 pH units increase over that of the boiler feed water.

☐ *(ii) How can the liquid condensate sample in laboratory simulate that from a boiler in the field ?*

The sampling setups are very similar (see Figures 1, 12 and 13). Both the laboratory and the boiler use softened boiler feed water to generate wet steam under nearly identical conditions (temperature ranges from 200 to 300° C, pressure ranges from 5 to 15 MPa). Both use the same sampling procedures and under the same conditions. Therefore, the liquid condensate E is equivalent to the boiler liquid effluent, and the steam generator fluid F equivalent to the fluid in the boiler and in the wellbore.

☐ *(iii) Why can one not regard the pH of boiler liquid effluent as that of the liquid in the wellbore ?*

As previously mentioned, the liquid in the boiler contains about 300 mg/l of $[HCO_3^-]$. When this liquid is passed through the intermediate condenser and is depressurized to atmospheric conditions, $[HCO_3^-]$ in the liquid decomposes and the gaseous CO_2 escapes to the atmosphere, with the associated $[OH^-]$ and $[CO_3^{-2}]$ remaining in the liquid. Hence, the pH of the boiler liquid effluent is significantly greater than that of the boiler feed water. The conditions under which the pH of the boiler liquid effluent is determined are markedly different from that of the wet steam in the boiler and in the wellbore. Since there was no actual pH measurement taken for fluid in a wellbore, it would not be appropriate to conclude that a high pH environment similar to that measured in the boiler liquid effluent exists in the high pressure liquid in the wellbore. If non-ionic water or water containing no $[HCO_3^-]$ ions is used as boiler feed water, the pH measured in the boiler liquid effluent will be representative of that of the liquid under high pressure. For example, with sodium hydroxide solution as test fluid, the absence of $[HCO_3^-]$ makes the pH of the liquid condensate E and steam generator fluids F and D the same as that of the test fluid A (Figures 5 and 6). This differs from the findings with fluids containing $[HCO_3-]$ ions (Figures 2, 3 and 4).

The laboratory results show that:

In the process of taking the vapour condensate C sample under atmospheric pressure, the $[HCO_3^-]$ of the test fluid in the steam generator decomposes into CO_2 and the associated $[OH-]$ and

$[CO_3-^2]$. CO_2 rises to the vapour phase and part of it escape with the steam condensate sample. $[OH^-]$ and $[CO_3^{-2}]$ remain in the steam generator fluid D. $[HCO_3^-]$ in the liquid condensate E sample partially decomposes during the sampling process due to a pressure reduction, but the $[HCO_3^-]$ concentration in liquid sample residue F remains constant and is similar to that of the test fluid. The pH sequence for these samples are as follows (Figure 7):

vapour sample residue D > liquid condensate E > test fluid A →liquid sample residue F > vapour condensate C.

When taking liquid condensate E sample at high pressure, it was found that the $[HCO_3^-]$ decomposition in the sample is adversely affected by the sampling pressure. The higher is the sampling pressure the lesser the $[HCO_3^-]$ decomposition and the closer the pH to that of the test fluid A (from 11.4 decreases to 8.6). With high pressure wet steam in a closed system, the $[HCO_3^-]$ in the liquid phase can hardly decompose, even with the presence of a small quantity of CO_2; the CO_2 will react with the $[OH^-]$ in the liquid to form $[HCO_3^-]$.

The test results shows that at 280^0 C, the quartz sand will dissolve as much as 11.5% by weight after 8 hours if it is placed in a high pressure vessel containing liquid with pH greater than 11.0. Other literature has also reported that at 260 degrees C, one cubic meter of fluid with pH = 11.3 will dissolve 3.6 kg of SiO_2. From this data, it can be shown that after two huff and puff cycles, each well at Shanjiashi reservoir will have lost 9096 to 38890 kg of SiO_2. Since the injection steam temperature is 330 degrees C and the pH of the boiler liquid effluent is 11.7, the actual SiO_2 dissolution should be considerably higher. The gravel packing operations at Shanjiashi reservoir uses 1050 to 5230 kg of quartz sand at each producer. This amount of quartz sand will be completely dissolved along with some formation sand during the second steam injection cycle. The wire wrap screen adjacent to the production zone will be completely exposed and the well should encounter severe sand production problem.

In Shanjiashi reservoir, 32 wells have been put into production (Of these 32, 16 have completed the first huff and puff cycle, 4 the second). These wells do not encounter a sand production problem, the oil has less than 0.01 % sand. 4 of these wells are in their third huff and puff cycle.

The pure quartz sand samples recovered from the field test after one huff and puff cycle show a weight loss in the range of 0.3 to 0.6 %. The recovered quartz sand samples are light gray in colour after they are cleaned with steam, carbon tetrachloride, and gasoline. They are not covered by an "alkaline resistant" carbon compound. This findings suggest that the quartz sand dissolves slightly due to heat [16,17], but not due to high temperature alkaline fluid in the wellbore.

The injection steam temperature for the three heavy oil fields previously mentioned approaches 350 degrees C, and the pH of boiler liquid effluent is in the range of 11 to 11.4. If the pH of the steam condensate in the wellbore is in the same range, then quartz sand cannot be successfully used as a sand control material. The field results do not support this conclusion. The measured pH of the bottom hole steam condensate samples taken at high pressure and high temperature range from 8.2 to 8.6. This does not support the inference that the liquid downhole in a steam injector has a high pH level.

4 CONCLUSIONS

From the test data and the field results, it can be concluded that :

(i) The main cause for the pH increase in the boiler liquid effluent is the decomposition of $[HCO_3^-]$ in a high temperature liquid when the confining pressure is being reduced. With the absence of $[HCO_3-$

] in the liquid, the pH remains unchanged with the reduction in pressure.

(ii) For boiler feed water with a [HCO_3^-] concentration less than 1000 mg/l, the pH increase in the boiler liquid effluent can be theoretically calculated. With [HCO_3^-] greater than 1000 mg/l, the corresponding pH increase is reduced.

(iii) [HCO_3^-] of the liquid inside the boiler decomposes while taking the steam condensate sample in atmospheric conditions. Part of the CO_2 escapes with the steam condensate, while the associated [OH^-] and [CO_3^{-2}] remain with the liquid in the boiler and increases its pH.[HCO_3^-] in the high temperature liquid condensate decomposes as the pressure is reduced during the sampling process. Gaseous CO_2 escapes to the atmosphere, the alkaline ions remains in the liquid and increase the pH. As the sampling pressure increases, the [HCO_3^-] decomposition and the increase in pH decreases. The pH and the ion concentrations approach that of the boiler feed water as the sampling pressure approaches the pressure in the boiler.

(iv) In a high temperature and high pressure environment and in a static condition, the quartz sand dissolves slightly in distilled water and in softened boiler feed water; however, it dissolves significantly in liquid with pH greater than 11. After one huff and puff production cycle, the quartz sand samples show only slight thermal dissolution, and no significant alkaline dissolution.

(v) The ion concentrations and pH of liquid sample taken downhole are very similar to that of the boiler feed water.

(vi) Quartz sand has been used successfully as gravel packing materials for long term sand control in huff and puff producers.

In short, [HCO_3^-] in the liquid downhole of a huff and puff well does not easily decompose, the pH of the liquid remains low, and therefore pure quartz sand can be used successfully in thermal recovery operation as gravel packing material for sand control.

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Table 1
Water Quality of Boiler Feed Water & Liquid Condensate

Field	Water Sample		Ion Concentration (mg/l)								Remarks
	Type	pH	HCO_3^-	CO_3^{-2}	OH^-	Cl^-	SO_4^{-2}	Na&K+	Ca&Mg	Salinity	
Gao-Sheng In Liao-He	Feed Water	7.4 -7.8	329 -396	30	0	35 - 40	0	147	0	541 - 613	
	Liquid Condensate	11.5	0	159 - 168	177 - 185	108 - 115	0	436	0	880 - 904	
Shanjia-shi In Sheng-Li	Feed Water	7.8 -8.4	311	48	0	525	10	490	1	1384	
	Liquid Condensate	11.4	0	122	297	1156	25	1161	1	2762	
Field in U.S.A.	Feed Water	8.1	406	24	0	13	251	261	0.2	955	
	Liquid Condensate	12.4	0	336	387	51	1210	1269	0.2	3253	Ref. 1

Table 2
Water Quality Analysis of Liquid Condensate Sampler

Test No	Sampling Conditions			Liquid phase					Remarks
		Pressure (MPa)				Ion Concentration (mg/l)			
	Temp. (°C)	Steam Generator	Container 13 in Fig. 13	Liquid sample	pH	HCO_3^-	CO_3^{-2}	OH^-	
1				Test Fluid A	8.2	428	46	0	Average value from all test
2	260 - 310	15.5 - 6.5	15.0 - 0	Liquid Condensate Residue F	8.1 - 8.2	430	42	0	As above
3	290 - 310	15.5	15.5	Liquid Condensate E	8.6	370	76	0	Valve 5 in Fig. 13 leaked slightly during tests
4	290 - 310	14.5	10.5	Liquid Condensate E	9.0	116	182	0	Valve 5 in Fig. 13 leaked slightly during tests
5	260 - 280	7 - 7.5	5.5	Liquid Condensate E	9.5	18	249	0	Valve 5 in Fig. 13 leaked slightly during tests
6	290 - 310	15 reduced to 6.5	0 - 0.02	Liquid Condensate E	9.9	0	237	17	Container 13 in Fig. 13 was empty, valves 9 & 10 were closed.
7	290 - 310	15 reduced to 7.5	0	Liquid Condensate E	11.4	0	147	68	Container 13 in Fig. 13 was empty, valves 9 & 10 were opened, 13 at ambient pressure.

Table 3
Dissolubility of Gravel Packing Materials in High Pressure Environment

Sampling Conditions						Gravel Dissolubility %		
Test No	Test Solution	pH Before	pH After	Duration of Constant Temp. (hrs)	Type of Gravel Packing Material	230 °C 5 MPa	260 °C 10 MPa	280 °C 12 MPa
1	Distilled Water	6.6	6.0	8	Quartz Sand A*	0.05	0.1	0.2
2	Distilled Water	6.6	6.0	8	Quartz Sand B*	0.05	0.1	0.2
3	Distilled Water	6.6	6.0	8	Ceramic Bead C*	0.3	0.35	0.4
4	Softened Boiler Feed Water	8.2	6.0	4	Quartz Sand A	0.05	0.15	0.2
5	Softened Boiler Feed Water	8.2	6.0	4	Quartz Sand B	0.1	0.2	0.5
6	Softened Boiler Feed Water	8.2	6.0	4	Ceramic Bead C	0.3	0.4	0.8
7	Softened Boiler Feed Water	8.2	6.0	8	Quartz Sand A	0.1	0.35	0.6
8	Softened Boiler Feed Water	8.2	6.0	8	Quartz Sand B	0.1	0.2	0.7
9	Softened Boiler Feed Water	8.2	6.0	8	Ceramic Bead C	0.8	0.8	0.9
10	Softened Boiler Feed Water	8.2	6.0	24	Quartz Sand A	0.2	0.45	0.6
11	Softened Boiler Feed Water	8.2	6.0	24	Quartz Sand B	0.3	0.5	0.8
12	Softened Boiler Feed Water	8.2	6.0	24	Ceramic Bead C	0.9	0.9	1.0
13	Softened Boiler Feed Water	8.2	6.0	72	Quartz Sand A	0.3	0.45	0.6
14	Softened Boiler Feed Water	8.2	6.0	72	Quartz Sand B	0.4	0.6	0.9
15	Softened Boiler Feed Water	8.2	6.0	72	Ceramic Bead C	1.0	1.2	1.2

16	Sodium Bi-carbonate	8.2	6.0	8	Quartz Sand A	0.45	0.45	0.6
17	Sodium Bi-carbonate	8.2	6.0	8	Quartz Sand B	0.4	0.5	0.9
18	Sodium Bi-carbonate	8.2	6.0	8	Ceramic Bead C	0.9	1.0	1.1
19	Sodium Hydroxide	8.6	6.0	8	Quartz Sand A	0.3	0.5	0.6
20	Sodium Hydroxide	8.6	6.0	8	Quartz Sand B	0.3	0.4	0.6
21	Sodium Hydroxide	8.6	6.0	8	Ceramic Bead C	0.4	0.45	0.6
22	Sodium Hydroxide	11.2	7.1	8	Quartz Sand A	0.4	0.6	0.9
23	Sodium Hydroxide	11.2	7.1	8	Quartz Sand B	0.5	0.6	0.9
24	Sodium Hydroxide	11.2	7.1	8	Ceramic Bead C	0.4	0.6	0.8
25	Sodium Hydroxide	11.8	9.0	8	Quartz Sand A	1.0	1.2	1.5
26	Sodium Hydroxide	11.8	9.0	8	Quartz Sand B	1.1	1.4	1.9
27	Sodium Hydroxide	11.8	9.0	8	Ceramic Bead C	2.0	2.0	2.5
28	Sodium Hydroxide	12.4	11.0	8	Quartz Sand A	8.9	10.0	11.5
29	Sodium Hydroxide	12.4	11.0	8	Quartz Sand B	8.6	12.4	11.5
30	Sodium Hydroxide	12.4	11.0	8	Ceramic Bead C	+0.4	+1.8	+5.0

*Note Quartz Sand A is sand from Rong-Cheng, quartz sand B is sand from Lan-Chow
Ceramic Bead C is from Tang-Shan

Table 4
Steam Injection Condition

Well Name	Wellhead		Steam Injection		Steam Quality %	Remarks
	Temperature (°C)	Pressure (MPa)	Duration (Days)	Volume (MP)		
Shen 2-6	349 - 357	14.4-16.3	14.4	3051	76	Volume of boiler feed water
Shen 2-11	340 - 351	13.4-16.1	17.4	4056	69	

Table 5
Weight Loss Measurement of Gravel Packing Materials After One Injection Cycle

		Type of Material							
		Quartz Sand						Ceramic Bead	
		From Rong-Cheng		From Jiang-Xi		From Lan-Chow		From Tang-Shan	
		Before	After	Before	After	Before	After	Before	After*
Weight (g)		100.0	99.7	100.0	99.4	100.0	97.4	100.0	110.3
Sieve Analysis (% by weight)	10 mesh	4.6	3.6						
	12 mesh	93.9	95.0						
	16 mesh	1.5	1.4			19.7	15.9		
	20 mesh			8.2	7.1	54.0	55.7	3.2	
	40 mesh			91.7	92.0	25.3	28.0	96.6	
	40 mesh			0.1	0.9	0.5	0.4	0.2	
Composition (% by weight)	Quartz	99.4 (10-16 mesh)		99.11 (20-40 mesh)		95.35 (20-40 mesh)			
	Impurities	0.6		0.89		4.65			

* the beads lumped together after the test

Table 6
Water Quality Analysis

		Ion Concentration(mg/l)				Steam Injection Conditions			
Well Name	Water Sample	pH	HCO_3^-	CO_3^{-2}	OH-	Pressure (MPa)	Temperature (°C)	Steam Quality (%)	Remarks
	Boiler Feed	8.4	543	13	0				
Shen	Boiler Effluent	11.75	0	299	164	14	315	31	
2-16	In the Tubing (15 m deep)	8.2	575	0	0	13		22	
	Boiler Feed	8.3	484	0	0				
Shen	Boiler Effluent	11.6	0	268	145	14.5	320	53.1	Steam
51	Bottomhole (1030m deep)	8.6	451	45	0			38.5	vent

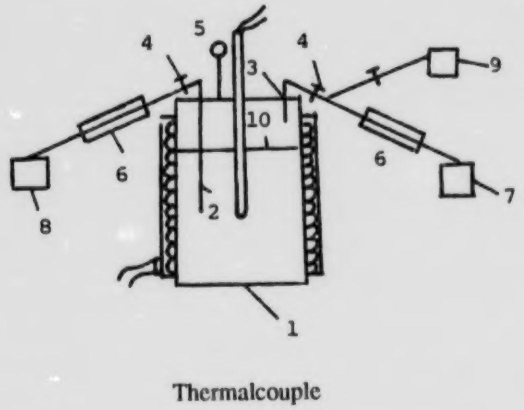
Table 8
Theoretical Relationship of HCO_3^- & pH Value

Boiler Feed Water				Boiler Effluent (after HCO_3^- decomposition)				
HCO_3^-	(a)		OH^-	HCO_3^-		OH^- (X)		
(mg/l)	g/l	N (Equivalent weight)	(mg/l)	(mg/l)	g/l	N	$pOH = \log_{10}N$	pH = 14
61×10^{3}	61	1	0	0	17	1	0	14
61×10^{2}	61×10^{-1}	1×10^{-1}	0	0	17×10^{-1}	10^{-1}	1	13
61×10	61×10^{-2}	10^{-2}	0	0	17×10^{-2}	10^{-2}	2	12
61	61×10^{-3}	10^{-3}	0	0	17×10^{-3}	10^{-3}	3	11
61×10^{-1}	61×10^{-4}	10^{-4}	0	0	17×10^{-4}	10^{-4}	4	10
61×10^{-2}	61×10^{-5}	10^{-5}	0	0	17×10^{-5}	10^{-5}	5	9
61×10^{-3}	61×10^{-6}	10^{-6}	0	0	17×10^{-6}	10^{-6}	6	8
61×10^{-4}	61×10^{-7}	10^{-7}	0	0	17×10^{-7}	10^{-7}	7	7

Table 7
Sealed Results of Using Quartz Sand as a Gravel Packing Material

Field Name		Cate Valley (1)			Shanjiashi			Gao-Sheng
Reservoir Depth (m)		914 - 1220			1140 - 1200			1550 - 1660
Oil Density (g/cm3)		1.0 - 1.1			0.98 - 1.0			0.94 - 0.98
Steam Injection Conditions	Temperature (°C)	340			318 - 357			310 - 350
	Pressure (MPa)	14 - 21			11 - 16			11 - 16
	Steam Quality (%)				40 - 60			40 - 70
	Cycle Time (days)				10 - 15 (shut in 3 - 4 days)			10 - 15
	Volume (tonnes)				3000 - 4000 (max. is 6411)			2000 - 3000
pH of Boiler Effluent					11.5 - 11.8			11.4 - 11.7
Gravel Packing Material (mm)		Quartz Sand			Rong-Cheng Quartz Sand (0.8 - 1.6)			Quartz Sand (0.8 - 1.2)
Huff and Puff Results	No. of Injection Cycles	1	2	3	1	2	3	1
	Total No. of Wells	167	78	27	31	9	4	20
	No. of Successful Wells	159	70	26	29**	9	4	20
	Success Ratio (%)	95.2*	89.7*	96.3*	93.5	100	100	100
Results		No sand production problems (1965 - 1973)			18 producers, daily production is 898 tonnes, cum. injection = 115000 tonnes, cum. production = 244000 tonnes (up to end of June, 1986)			No sand production.
Remarks		* success ratio is referred to success in sand control and production increase			** screen in two wells were damaged			

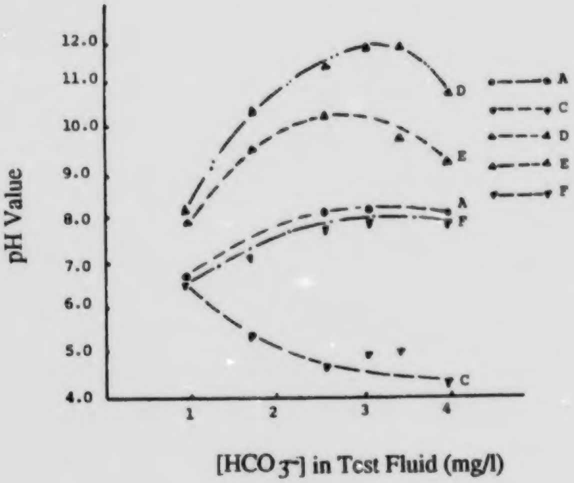
Figure 1
Set Up of High Pressure Steam Generator Experiment



LEGEND

1. High Pressure Steam Generator
2. Steam Liquid Sampling Tube
3. Steam Vapour Sampling Tube
4. Needle Valve
5. Pressure Gauge
6. Condenser
7. Vapour Condensate
8. Liquid Condensate
9. Saturated Ca(OH)‰2 Solution
10. Vapour / Liquid Interface

Figure 2
ph and [HCO3⁻] Concentration Correlations



LENGEND

Test Fluid A

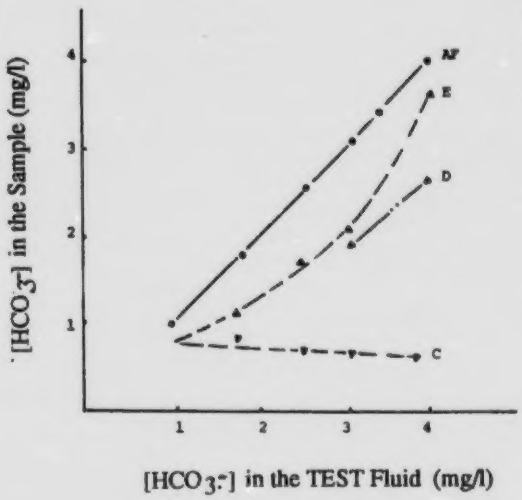
Vapour Condensate C

Vapour Sample Residue D

Liquid Condensate E

Liquid Sample Residue F

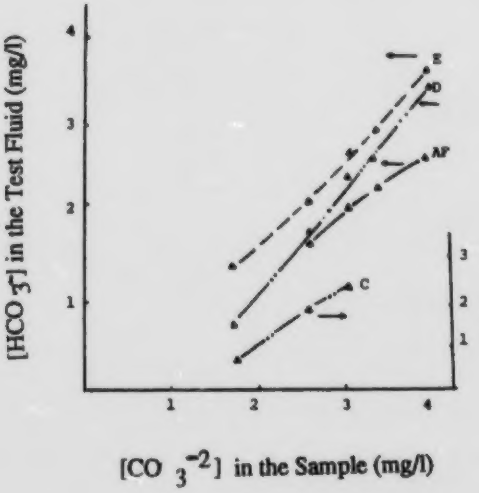
Figure 3
The [CO_3^-] Variations in Different Samples



LEGEND

Same as in Figure. 2

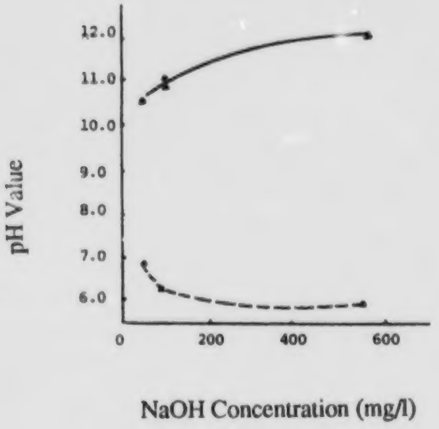
Figure 4
The [CO_3^{-2}] Variations in Different Samples



LEGEND

Same as in Figure 2.

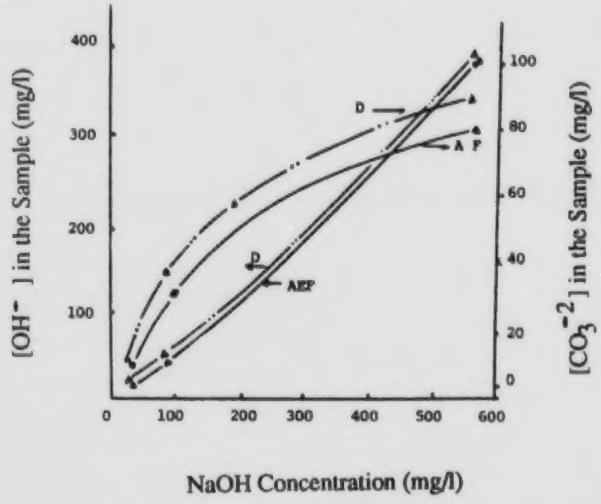
Figure 5
pH and NaOH Concentrations Correlation



LEGEND

Same as in Figure 2.

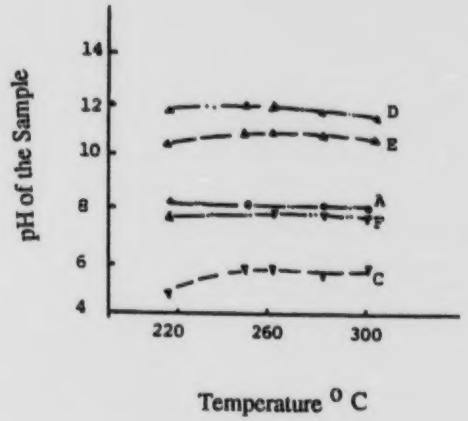
Figure 6
Variations of $[OH^-]$ and $[CO_3^{-2}]$ in Different Samples



LEGEND

Same as in Figure 2.

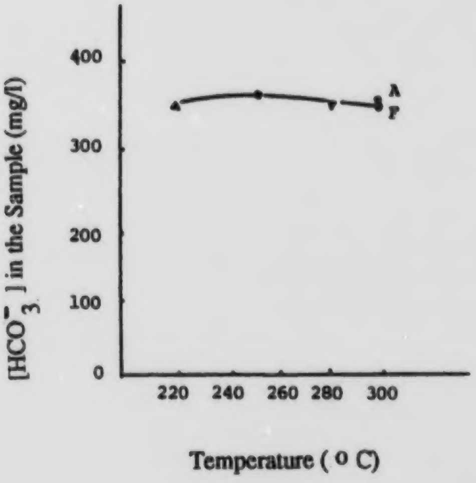
Figure 7
pH and Temperature Variations with Softned Boiler Feed Water as the Test Fluid



LEGEND

Same as in Figure 2.

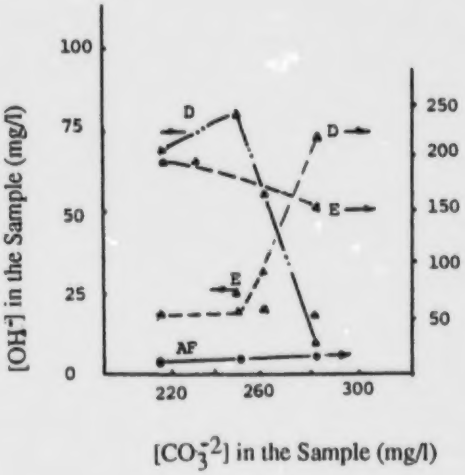
Figure 8
[HCO_3^-] and Temperature Correlations with Softned Boiler Feed Water as the Test Fluid



LEGEND

Same as in Figure 2.

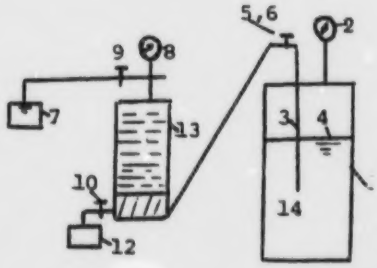
Figure 9
Variations of $[OH^-]$ and $[CO_3^-]$ with Temperature Using Softned Boiler Feed Water as the Test Fluid



LEGEND

Same as in Figure 2.

Figure 10
Experimental Set up for Sampling Liquid Condensate at High Back Pressure



LEGEND

1. High Pressure Steam Generator
2, 8. Pressure Gauges
3. Liquid Condensate Sampling Tube
4. Vapour / Liquid Interface
5, 6, 7, 9 10. Needle Valves
7. Connecting Tubing
11. Kerosene Collector
12. Liquid Condensate E Collector
13. High Pressure Container, Filled with Kerosene.
14. Fluid in the Steam Generator (Test Fluid A Before the Test, Liquid Sample Residue F After the Test)

Figure 11
Bottomhole Test Joint

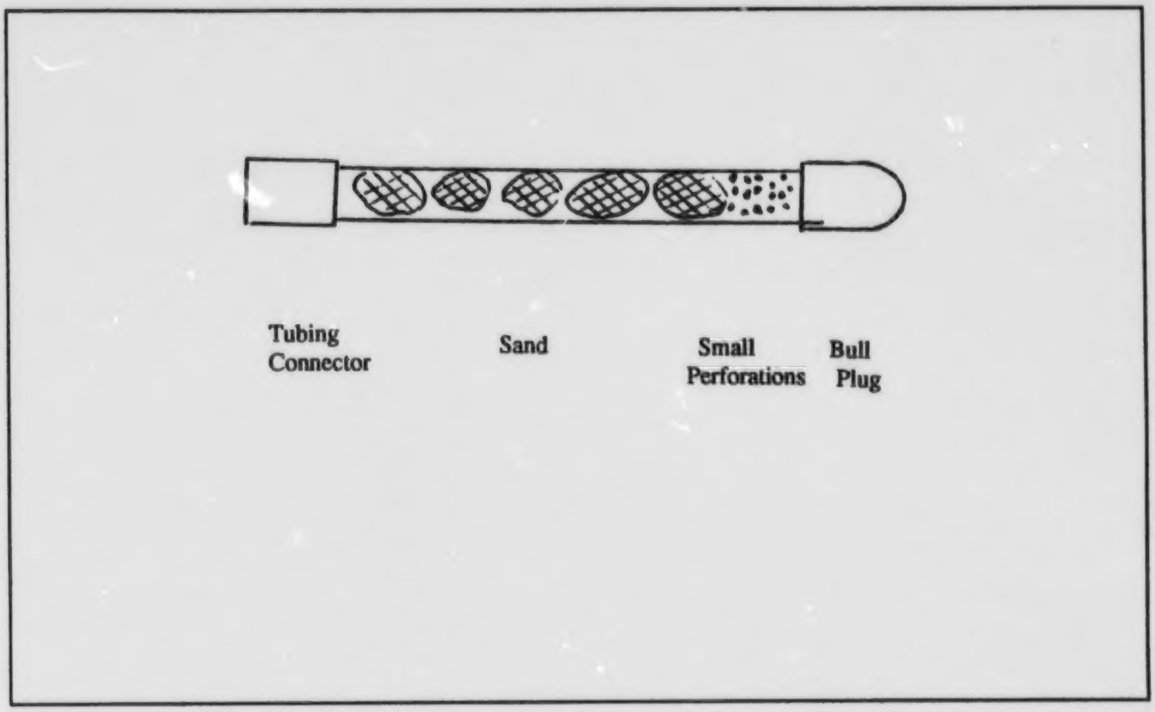

Tubing Connector
Sand
Small Perforations
Bull Plug

Figure 12
Liquid Condensate Sampling Diagram

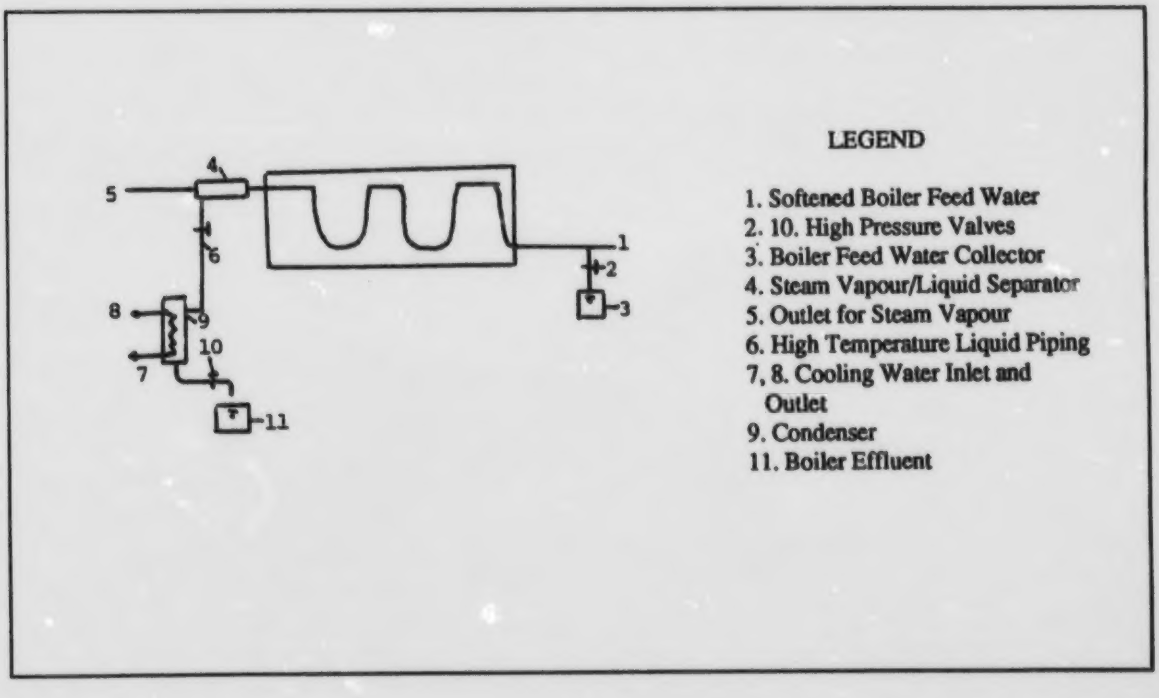
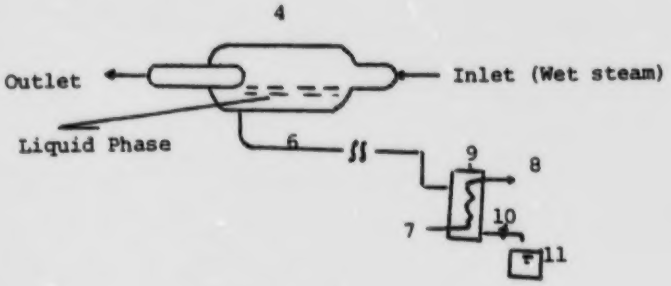

5
4
6
1
2
3
8
9
10
7
11
LEGEND
1. Softened Boiler Feed Water
2. 10. High Pressure Valves
3. Boiler Feed Water Collector
4. Steam Vapour/Liquid Separator
5. Outlet for Steam Vapour
6. High Temperature Liquid Piping
7, 8. Cooling Water Inlet and Outlet
9. Condenser
11. Boiler Effluent

Figure 13
Detailed Diagram for Boiler Effluent Sampling


4
Outlet
Inlet (Wet steam)
Liquid Phase
6
9
8
7
10
11

LEGEND

Same as in Figure 12.

25

SAND CONTROL TECHNIQUES FOR THERMAL RECOVERY OF HEAVY OIL

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ABSTRACT

Conventional slotted liners and gravel packing have been used for sand control during steam and hot water floods in the unconsolidated Athabasca and Lloydminster formations. Unsatisfactory performance has occurred primarily due to the extremely erosive and corrosive environment existing in the wells.

In this paper, several solutions to this problem are discussed. Prefabricated sand control filters using novel materials are shown both in the lab and in the field to be capable of providing adequate sand control.

1. INTRODUCTION

Many of the past in-situ thermal recovery projects in Alberta's oil sands have been adversely affected by sand production and/or productivity reduction caused by sand control measures.[1] In projects utilizing vertical wells with slotted liners, unsatisfactory performance has been observed due to plugging of some slots leading to high velocities and erosion in others. This causes large amounts of sand to enter the wellbore and production is lost. For processes utilizing horizontal wells, the combination of unconsolidated oil sands and relatively low velocities make it likely that any sand entering the wells will settle and accumulate. Published data from an Elf-Aquitaine horizontal well project, and, reports from the Texaco Athabasca pilot and the San Ardo field confirm that difficulties have been encountered with current sand exclusion techniques.

Because of these problems, the Alberta Research Council began a combined field and laboratory study of solids control methods suitable for the harsh conditions encountered during thermal recovery of heavy oil. Several new methods including:

- *a patented[2] prepacked filter, utilizing stainless steel wool sandwiched between coarse steel cloth, and*
- *a composite filter media in a wire-wrapped screen module, were developed[3,4] and tested. In this paper, both the laboratory and field tests are discussed.*

2. LABORATORY APPARATUS

Downhole conditions in thermal recovery wells are particularly severe. Wide variations in pH (5-12), temperature (15-350°C) dissolved solids content, and high oxidation or sulphidation potentials are common. In order to assess the performance of various candidate sand control devices, two test systems were developed to simulate these in-situ conditions.

2.1 Flow Through Steam Apparatus

A flow-through apparatus shown in Figure 1 was constructed, which enabled continuous exposure of test samples to fresh aqueous solutions. The test set up consisted mainly of a temperature controlled autoclave containing the test material to be evaluated. The test sample was enclosed in a 1/2" diameter stainless steel tube 6" long equipped with stainless steel mat filters and fittings at each end for connection to a flow system. Electric heaters operating through a controller maintained a pre-set temperature within the autoclave. Pressurized water acted as a heat transfer medium to the sample holder. Injection through the system was by a HPLC pump at a controlled rate. Back pressure was maintained high enough to ensure that the fluid passing through the sample always remained in the liquid state.

Na_2CO_3 was used to adjust the pH level for the dissolution tests. A solids separation vessel was connected to the effluent upstream of the back pressure regulating valve to isolate the latter from solids which may precipitate as a result of dissolution followed by cooling.

This apparatus was used to screen materials for use in the severe conditions encountered in in-situ production. The flow test procedure required that a sample of candidate material be dried overnight at 110°C and weighed before being placed in the holder. Fluid injection was for 72 hours after the preset temperature had been attained. At the completion of the 72 hour period, the heaters were turned off and distilled water flushed through for approximately 1 hour. The post-run sample was then dried overnight at 110°C and the weight loss calculated.

Potential filter media materials such as:

- ☐ *Ottawa sand,*
- ☐ *sintered bauxite,*
- ☐ *cement clinker,*
- ☐ *zirconium oxide,*
- ☐ *nickel pellets, and*
- ☐ *nickel coated sands*

were tested. A comparison was made between the performance of these materials after exposure to identical thermal and hydrolytic conditions, and these results are reported in Section 3.

2.2 Standard Solid Control Test Cell

In order to study in more detail the overall behaviour of different solids control systems, another experimental cell was designed that could be operated with liquids or steam flowing through oil sands at high temperature and pressure (Figure 2). The cell included an injection head, equipped to measure pressure and temperature, and a production head which separated the solids from the bitumen and water that is produced. A core of the formation to be tested was placed between the two heads and surrounded by a lead sleeve, to which external pressure was applied using nitrogen. This pressure simulates the effect of overburden loading.

The solids control system to be tested was placed within the lead sleeve and between the sample and production head. To carry out a test, the whole assembly described above was placed in a high pressure vessel (Figure 2). The test cell was then connected to the injection and production piping as shown. Prior to commencing fluid injection into the cell, the thermostatic bath heated the core to a temperature of 90°C. Once isothermal conditions were achieved, fluid injection began. Generally the conditions for saturated steam injection was a temperature of 140°C, corresponding to a pressure of 363 KPa, and a velocity of 600 m/h. The injection conditions when hot water was used was 90°C and a velocity of 13 m/h. The high velocity used for these tests simulates situations created around a well during the drawdown stage of a steam stimulation.

3. RESULTS AND DISCUSSION

3.1 Lab Results, Composite Media

Table 1 shows the results from dissolution tests done in the Flow Through Steam Apparatus. The performance of nickel coated sand is compared to that of sintered bauxite, Ottawa sand, cement clinker, and zirconium oxide. All samples were exposed to identical conditions of flowing pH 11 steam condensate at 300°C for 72 hours at a rate of 3.0 $cc/min.\ cm^2$. Bauxite, Ottawa sand, and zirconium oxide showed severe weight losses under the above thermal and hydrolytic conditions. In contrast, little or no loss was observed in the nickel coated sand samples. Cement clinker showed an intermediate level of loss under the alkaline test conditions.

Table 2 shows weight losses from tests with various materials at pH's ranging from 4.75 to 11.3. Because Na_2CO_3 was used to adjust the alkalinity of the injected solution, a pH 11.3 is considered to possess quartz dissolution characteristics equivalent to that of a pH 12 NaOH solution. In addition, solutions adjusted to this pH with sodium carbonate (Na_2CO_3) resist pH decline much better through a buffering action. Similar behaviour was observed by Reed in dissolution experiments done with quartz gravel pack and formation sandstone[9]. As expected, nickel sand weight loss from the pH 7 run was essentially nil, whereas results from the pH 11.3 experiment showed a dramatic increase.

Post-run microscopic inspection of nickel coated sand from the pH 11.3 run revealed a number of empty shells, each characterized by cracks and fissures on the nickel surface. It was apparent in this case that some form of corrosion had taken place which allowed the high pH solution to penetrate the resulting fissures in the nickel coating and dissolved the sand. A review of corrosion literature supports the fact that nickel can be highly corrodable at high pH. The work of Deltombe[10] et al shows theoretical domains of corrosion, immunity, and passivation of nickel at 25°C and shows qualitatively similar effects.

Runs at pH 11 and 7 revealed no physical damage to the nickel coating except for some slight discoloration. The same could not be said about the Ottawa sand and bauxite samples. The former showed severe erosion of the grain surface which resulted in an overall reduction of the grain size. Similarly, the bauxite samples also displayed considerable deterioration in the original shape and structure resulting in fines production and irregular shapes. In a field application, this observation raises a serious implication, since it means there is a possibility of plugging, due to migration of these fines or solid precipitates into parts of the reservoir.

Cement clinker, because of its chemical composition performed considerably better than the bauxites under alkaline conditions. However, because the acid number of the bitumens is typically 2 to 3mg KOH per gram of oil, an acid environment is expected during bitumen flow. An acidic environment was simulated for a test using 0.03 molal acetic acid plus 0.03 molal sodium acetate buffer, yielding an aqueous solution having a pH of 4.6 to 4.8 at room conditions. Repeating the test with this medium as the solvent produced a weight loss in the clinker of 29.3%. This suggests that the clinker would be incapable of providing satisfactory service over the anticipated pH range of exposure in the field, especially when thermal steam stimulation processes are applied. Nickel sand and metallic nickel on the other hand, exhibited a satisfactory loss level over the range of mildly acidic to basic, as demonstrated by the loss values shown in Table 2. No other material tested in this series had shown similar capability.

The performance of the zirconium oxide paralleled that of bauxite, but the post-run zirconium oxide exhibited considerable friability of the remaining granules under light abrasive action. The resulting fines combined with a form of cementing action produced a considerable reduction of permeability through the zirconium oxide pack.

■ 3.2 Field Test, Composite Media

Subsequent to the lab tests, filter modules shown schematically in Figure 3 were constructed[5] of inner and outer wire wrapped screen assemblies filled with candidate media such as the Ni coated sand. Four materials were chosen for testing as the filter media:

- ☐ *nickel coated sand,*
- ☐ *chromium clad steel shot,*
- ☐ *steel shot, and*
- ☐ *stainless steel shot.*

All four materials were run in a one-well test in separate modules to compare their performance under identical conditions. The test well was in the Cold Lake heavy oil region of Alberta. The producing zone was in the Maclaren formation. The API gravity and viscosity of the oil was about 11° and 50,000 cP respectively. The median grain size of the formation was 0.21 mm. Details of the design of the modules are given in Figures 4 and 5.

The expected production from past history of the well was 9 m^3/day. However, an average production of 7 m^3 oil/day was actually recorded while pumping at 85°C for 75 days. Also, communication from an offsetting well occurred during the producing cycle and the production actually increased to a high of 22 m^3/day. These production figures were encouraging as they indicated the pre-pack assembly was not restricting the production of oil.

The well was then steamed with 3636 m^3 of steam for 35 days and soaked for an additional 10 days. The well flowed for 44 days with a water cut of 95%. The well was placed back on pump for 14 days and then the bottom hole pump started to hang up. The liner hanger and liner assembly were then all pulled from the well.

After the removal from the test well, the separated filter modules were steamed off and transported off site for evaluation. Sections of each module were disassembled to examine the condition of the filter media by metallography. Other sections were removed and pressure tested with hot bitumen to assess qualitatively the residual permeability of each section. The results of the evaluations are summarized in Table 3 and 4.

From the evaluation of each filter module, it was concluded that the filter failure was due to the corrosive attack of Fe shot and Ni/Sand, with the reduced permeability of these modules, the internal pressure during steam injection "jetted" the attacked material out through the perforations, which allowed rapid sanding in of the well in the subsequent production cycle.

The SS shot had performed relatively well, although traces of carbonate scale were noted. The high initial packing density, the rougher surface and the less spherical nature of the particles of SS shot would, however, make it more susceptible to carbonate scale buildup and lower initial and long term permeability.

Chromium clad steel shot was not affected by downhole exposure. Neither surface corrosion or cladding deterioration was observed. The smooth, spherical shape of the Cr-Fe shot particles reduced carbonate scaling and kept pack permeability high. It was concluded that this media was the best for this particular application.

3.3 Laboratory Results, Texaco Filter

A new filter was first developed by Texaco Canada Resources Ltd. and the Alberta Research Council in support of Texaco's Athabasca field pilot. More recently, this type of filter has also been evaluated for possible use at AOSTRA's Underground Test Facility (UTF). Figure 6 shows the sand size distribution from core samples from these two locations.

The Texaco sands are fine-grained, generally in the range of 125 to 250 mm, but certain horizons contain a medium-grained sand and others have a higher silt content. The vertical lines in Figure 6a at 0.030" [0.76 mm], 0.020" [0.51 mm], and 0.015" [0.38 mm] represent typical slot widths for slotted liners and wire wrapped screens commonly used for sand control in the field.

The UTF sand is classified as fine and moderately well sorted, with a median grain size of about 175 µm (0.0069" or 80 mesh). The sand is finer and better sorted than the Texaco sands. The mineralogical composition of both is 91-97% quartz, with small amounts of chlorite and illite clays.

In the Texaco tests a total of 51 screening tests were carried out with the Standard Solids Control Cell (Figures 2a and 2b) to find the most suitable material, or combinations of materials, that would control sand movement, maintain high permeability, and yet be able to withstand the relatively hostile environment encountered in a thermal recovery process. The materials tested as potentially suitable candidates are listed in Table 5 together with the testing method.

For the first time a new type of filter using a compressed metallic wool and a metallic cloth (SWC) was designed and tested[3]. The metallic filter materials offered the advantage of good chemical and mechanical stability compared to those filters based on a silica sand and a bonded agent. A pressure drop test (Figure 7) indicated that the SWC filter was less liable to plugging than the other types of filters. These pressure drops were measured by flowing air at a pre-set rate through the filter before and after test runs in the Standard Solids Control Test Cell. For the post-run test, the residual bitumen had been removed from the filter with methyl chloride whilst ensuring the solids entrapped in the filter were relatively undisturbed. The combination of steel wool and a steel cloth was selected as the most efficient and economical solution for Texaco's solids control problem.

To operate as a filter, the steel wool is compressed within its elastic limits. The steel cloth serves to confine and compress the steel wool. In addition, this cloth improves the filtering ability of the steel wool by assisting the bridging of solids at the steel wool-steel cloth interface (Figure 8).

The capture of particles by the fibrous structure is strongly dependant on the probability of getting the particle in direct or close contact to the fiber. The more tortuous a filter material is, the greater the probability of capturing particles suspended in the flowing fluids. The degree of compression will increase both the tortuosity of the filter, and also the capture probability. The relative variation of capture probability $(CP)_r$ with the degree of compression was calculated using the pressure drop in the original (ΔP_O) and compressed (ΔP_C) material by:

$$(CP)_r = \Delta P_C / (\Delta P_O) \qquad (1)$$

where pressure drop was calculated by:

$$\Delta P = C_D (2\rho V_S^2 \quad (1-\varepsilon)/\pi e) \bullet (L/d_f) \qquad (2)$$

where:

V_S = the superficial velocity (cm/s)

L = depth of metallic wool (cm)

d_f = average cross section of metallic fiber (cm)

ρ = bulk density of the wool (g/cm^3)

ε = porosity of the wool

The relative capture efficiency was therefore defined as:

$$(CP)r = (C_{DC} (1-\varepsilon_C)\, \varepsilon_o\, L_C) / (C_{DO} (1-\varepsilon_O)\, \varepsilon_C\, L_O) \qquad (3)$$

The drag coefficient C_D was calculated using Ergun's equation[8]:

$$C_D = (\Pi/2Re)(1-\varepsilon/\varepsilon^2)(150 + 1.75\, Re\, (\varepsilon/1-\varepsilon))$$

where the porosity, ε, was replaced by compression factor k_o through the relationships

$k_o = (1-\varepsilon / 1-\varepsilon_o)$

where the porosity of the uncompressed steel wool having the volume $V(cm^3)$ the weight $G(g)$ and density of metal 7.8 g/m^3 is

$\varepsilon_o = 1-(G/7.8 \times V)$

For a medium size metallic wool (87 μm average cross section), the degree of elastic compression was calculated using the reference density:

$K_o = \rho/\rho_o$

where $\rho O = 0.0307$ g/cc.

The results of these calculations are illustrated graphically in Figure 9 which indicates the relative capture efficiency of a filter element as a function of the compression factor.

In order to establish the influence of grain size as well as compression on the efficiency of filtration, an experimental investigation was completed using the Standard Solids Control Cell and a medium grade metallic wool. The medium grade metallic wool was compressed at various factors and a filter depth of 1.9 cm was maintained constant. The results are shown in Figure 10 and indicate that in order to obtain a filtration efficiency in excess of 80%, the compression factor should be in excess of 8 for a medium grain size of 180 μm and in excess of 16 for 152 μm sand. Improvements in the design of this type of filter will be aided by more investigations into the dynamics of the mechanisms of external bridging and internal capturing. A good balance between pressure drop characteristics and capture efficiency is the major goal of such a design.

Based on this analysis, a Texaco filter having a compression factor of 20 was chosen[6] for evaluation as a possible sand control device for AOSTRA's Underground Test Facility (UTF). Oil sand from UTF cores was blended into uniform batches having a medium grain size of 150 μm. This was then tested in the Standard Solids Control Test Cell with either the Texaco filter, or wire wrapped screen used as the candidate solids control elements. Water at 200°C was injected through the core in three successive stages:

a) at rates increasing from 30 to 760 cc/hr. Sufficient back pressure to prevent flashing was maintained.

b) Flow was maintained at 760 cc/hr while temporarily lowering the back pressure on the core, causing water to flash within the core. This was repeated several times.

c) Back pressure was restored and flow rates were increased above 760 cc/hr by increments of 50-100 cc/hr, until the tests were completed.

Runs were terminated when either the pressure drop across the core and filter exceeded 300 kPa, the lead sleeve surrounding the core collapsed due to excessive solids production, or the maximum flow rate was achieved.

Figure 11 summarizes the test findings. The 0.010" wire wrapped screen allowed approximately 10 times more solids production than the steel wool filter. As a result of these tests, three elements were selected for field testing; one in each well pair of the Phase A of the UTF:

1. Texaco steel wool filter,
2. 0.010" wire wrapped screen,
3. 0.005" wire-wrapped screen.

All of these gave encouraging results in the laboratory program, but, there are trade-offs among them that can only be evaluated in the field. The Texaco filter is probably the most resistant to erosion and plugging, because of the high porosity and resilience of steel wool, but, it is currently more expensive than wire-wrapped screens. The 0.010" wire wrapped screen is closest to conventional practice, but may allow more solids production than is desirable in a horizontal well. The 0.005" screen is expected to allow little solids production, but the small gaps may be unduly sensitive to scaling or plugging.

3.4 Field Test, Texaco Filter

A field test was carried out at Texaco's Ft. McMurray Pilot by placing a 9 m length of the Texaco filter in the vertical well P15 at the south-west corner of Pattern I of the pilot (see Figure 12). Figure 13 shows the completion of P15 after the filter was positioned. A second well TH5 (located only 8 m away from P15) was used as an injection well. Steam was injected into TH5 and when sufficient bottom-hole pressure was established P15 was placed on production.

A second test was carried out in Pattern II at the pilot (Figure 12). In this test, the existing slotted liner in well PI34 was removed and analyzed and replaced by a 20 foot section of steel wool filter placed in the lower section of the well.

Permeability of a new filter of approximately 3600d was reduced to an average of approximately 900d in the first three months of operation in the harsh environment. It was calculated that approximately 95% of plugging will be achieved after 134 months of exposure and skin effects in the well will be comparable to a slotted liner after about two months of exposure. The larger open area of thee SWC filter as compared to conventional slots acts favourably to increase the life of the new filter.

Production fluids were monitored during both the above tests as were the pressure drops across the filter. Field tests and their analyses are still in progress, but to date the control of solids has been very successful and plugging of the filter has not been a problem.

4. SUMMARY AND CONCLUSIONS

Several new materials were tested in laboratory simulations of the severe conditions encountered in thermal recovery. A nickel coated sand product worked well in the lab, but, appeared to have failed a field test. However, a Cr coated Fe shot was also successfully developed and performed well as a filter media in the field test.

A new metal wool filter (SWC) was also developed in the lab and tested successfully in one field application. Future field tests are underway.

In conclusion, both the wire wrapped screen/filter media modules and the Texaco SWC filter appear to have great promise for being able to provide sand control systems for thermal recovery processes.

5. REFERENCES

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- 9. Reed, M. G.; "Gravel Pack and Formation Sandstone Dissolution During Steam Injection", Journal of Petroleum Technology, pp. 941-948, June 1980.
- 10. Deltombe, E., deZoubov, N., and Pourbaix, M.; "Atlas of Electrochemical Equilibria in Aqueous Solutions", Marcel Pourbaix, N.A.C.E. pp. 330-342, 1974

TABLE 1
WEIGHT LOSS RESULTS FROM DISSOLUTION TESTS
300°C, pH 11

Sample (20/40 Mesh)	Weight Loss (%, wt/wt)	
Ni Coated Sand 1*	0.15	Gain
Gain Ni Coated Sand 2**	0.8	
Sintered Bauxite	38.7	
Ottawa Sand	72.5	
Cement Clinker	6.3	
Zirconium Oxide	29.0	

*Process 1: Electroless plating process from ref. (7)
**Process 2: Hydrometallurgical coating process from ref (8)

TABLE 2
WEIGHT LOSS OF VARIOUS GRAVEL PACK MATERIALS AS A FUNCTION OF pH (72 h Exposure at 300°C)

Sample	pH	Weight Loss (%, wt/wt)
Ni Sand Gain 20/30 Mesh	4.75	0.07
Ni Sand Gain 20/30 Mesh	7.0	0.06
Ni Sand 20/30 Mesh	11.0	0.62
Ni Sand 20/30 Mesh	11.3	22.5
Cement Clinker 20/40 Mesh	11.0	6.3
Cement Clinker 20/40 Mesh	4.8	29.3
Metallic Nickel Gain 20/30 Mesh Shot	11.3	0.35

Note: All nickel sand samples were from the same batch processed using methods from ref. (8)

TABLE 3
METALLOGRAPHIC EXAMINATION OF FILTER MEDIA

Material	Surface Condition	Interstitial Pack
Cr-Fe Shot	Unaffected	Very fine formation sand
Fe Shot	Rough, Corroded Scale	Corrosion Scale
Ni/Sand	Rough Surface Cracked Particles	Corrosion Scale
SS Shot	Unaffected	Very fine formation sand Carbon scale traces

TABLE 4
POST-TEST PERMEABILITY TEST RESULTS

Material	Fluid Flow at Increasing Gas Pressure Through a Filter Section Removed from Test Filter Modules
Cr-Fe Shot	Uniform flow at <68.9 KPa (10 psi) increasing to 344.5 Kpa (50 psi)
Fe Shot	Spotty flow between 68.9 KPa to 103.35 KPa (10-15 psi), uniform flow at 137.8 KPa (+20 psi).
Ni/Sand	No flow < 275.6 KPa (40 psi (Section 1)), Flow at perforations at no applied pressure (Section 2 with holes in pack)
SS Shot	Uniform flow at < 68.9 KPa (10 psi) increasing to 344.5 KPa (50 psi).

TABLE 5
SUMMARY OF LABORATORY INVESTIGATIONS

Run No.	Package of Runs	Objectives	Type Filter* ID	Fluid Injected[2] ID	Formation Sample[3] ID
1	1 to 4	Test of equipment and method	100	10,11,20	OS,CS
2	5 to 9	Baseline runs	100	11	OS
3	10 to 14 and 17	Testing of the efficiency of various sizes of inorganic bounded silica sand	200	11	OS
4	15 to 21	Screening experiments using various filter materials	300,410, 411,500,600	11,20	OS
5	22 to 29	Preliminary experiments on SWC filters	410,411 420,421	10,11,20	OS,CS
6	30 to 38	Optimization of size of steel wool filaments vs formation	421	10	CS
7	39 to 44	Thee same as above, but using oil sands and steam	421	20	OS
8	45 to 51	Optimization of compression factor using clean sand-water	421	10	CS

*Type of Filter
100 slotted disk
200 consolidated sand (inorganic bond)
300 epoxy coated sand
400 steel wool (SW)
401 SW & S cloth
410 SW bulk
411 SW bulk and steel cloth
420 SW ribbon
421 SW ribbon and steel cloth
500 steel shot (unconsolidated)
600 steel cloth

[2] **Fluid Injected**

10 distilled water (25°C)

11 distilled water (93°C)

20 steam (134°C)

[3] **Formation Sample**

OS oil sand

CS clean sand

Figure 1
Schematic Diagram of Flow-through Apparatus Using Autoclave Heating

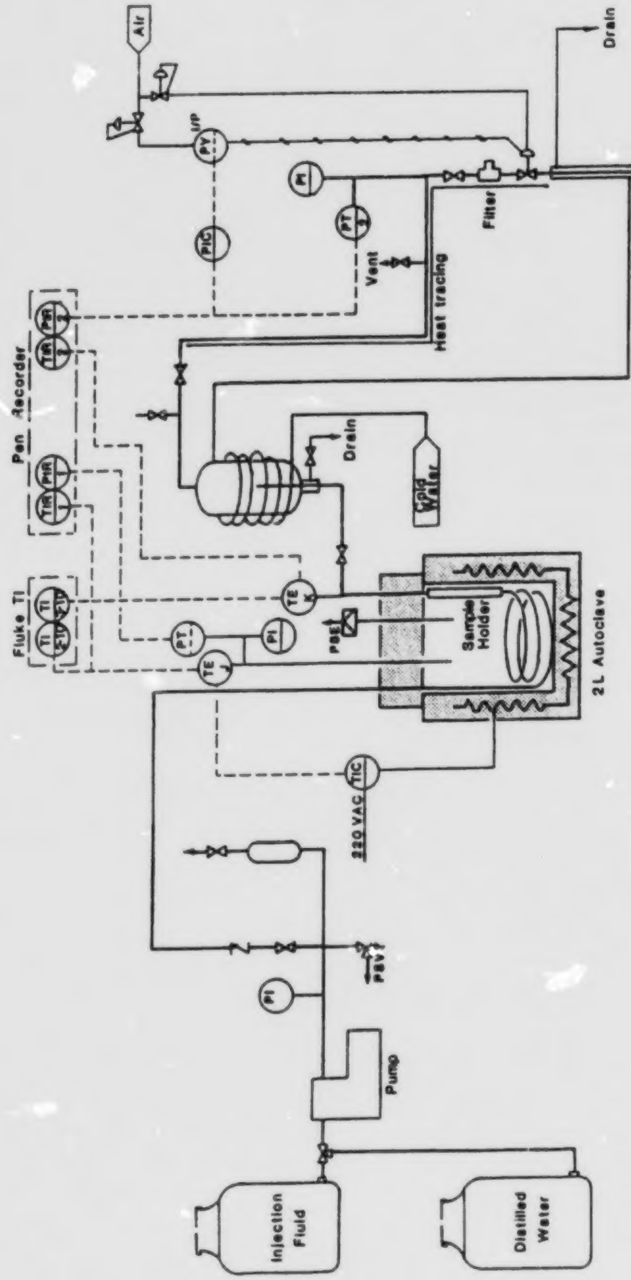

Air
Drain
I/P
PY
PI
PT
PIC
Vent
Heat tracing
Filter
Receiver
Pen Recorder
TIR
PIR
Fluke TI
TI 210
Cold Water
Drain
TE
PBE
Sample Holder
2L Autoclave
PT
PI
TE
TIC
220 VAC
PSV
PI
Pump
Injection Fluid
Distilled Water

Figure 2 (a)
Standard Cell For Testing The Effectiveness Of A Solids Control System

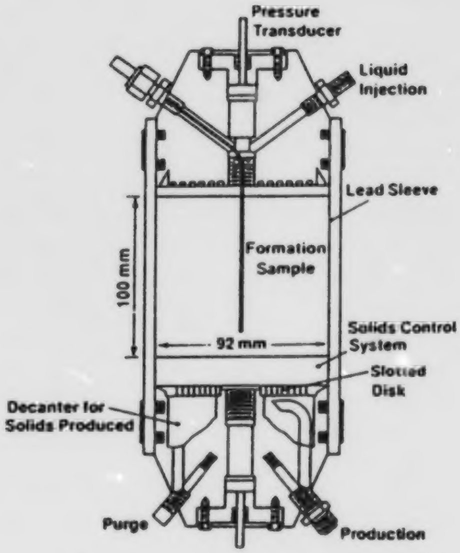

Pressure Transducer
Liquid Injection
Lead Sleeve
100 mm
Formation Sample
92 mm
Solids Control System
Slotted Disk
Decanter for Solids Produced
Purge
Production

Figure 2 (b)
Piping And Environmental Control

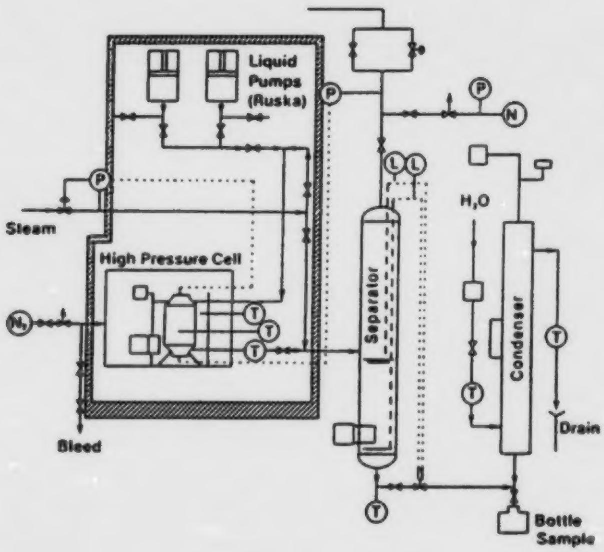

Liquid Pumps (Ruska)
P
P
N
L
L
H_2O
Steam
High Pressure Cell
N_2
T
T
T
Separator
Condenser
T
T
T
Drain
Bleed
Bottle Sample

Figure 3
A Cross-section of the Filter Module

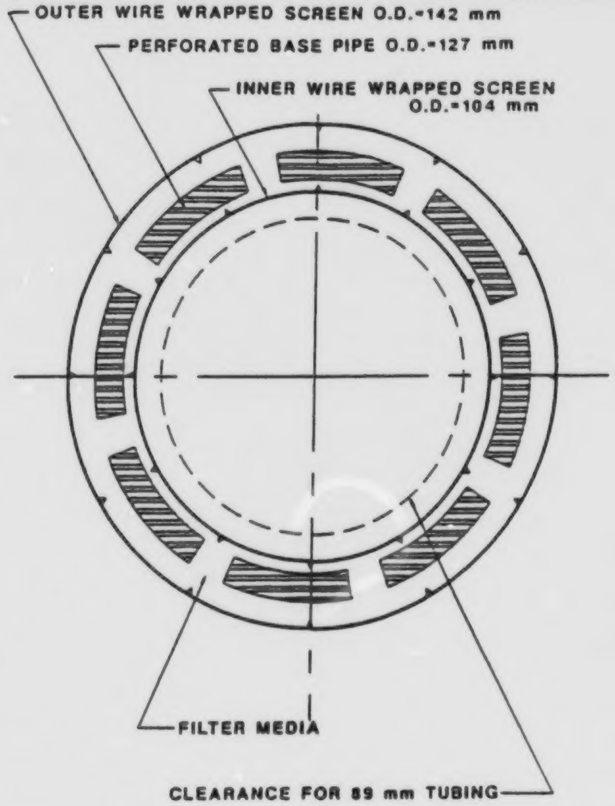

OUTER WIRE WRAPPED SCREEN O.D.=142 mm
PERFORATED BASE PIPE O.D.=127 mm
INNER WIRE WRAPPED SCREEN O.D.=104 mm
FILTER MEDIA
CLEARANCE FOR 89 mm TUBING

Figure 4
A Longitudinal Section of the Filter Prepack

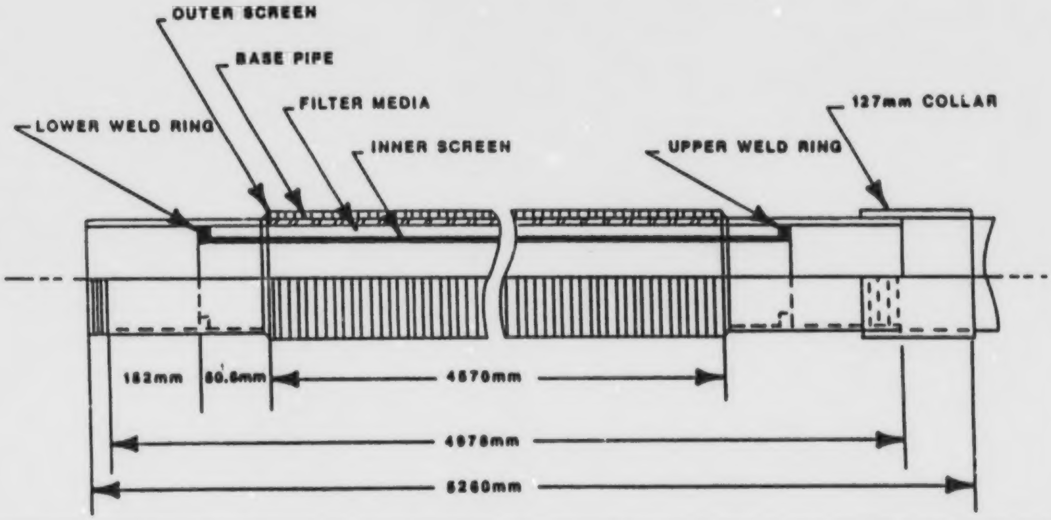

OUTER SCREEN
BASE PIPE
FILTER MEDIA
LOWER WELD RING
INNER SCREEN
UPPER WELD RING
127mm COLLAR
152mm
50.8mm
4570mm
4978mm
5260mm

Figure 5
The Configuration of Test Media in the Field Test

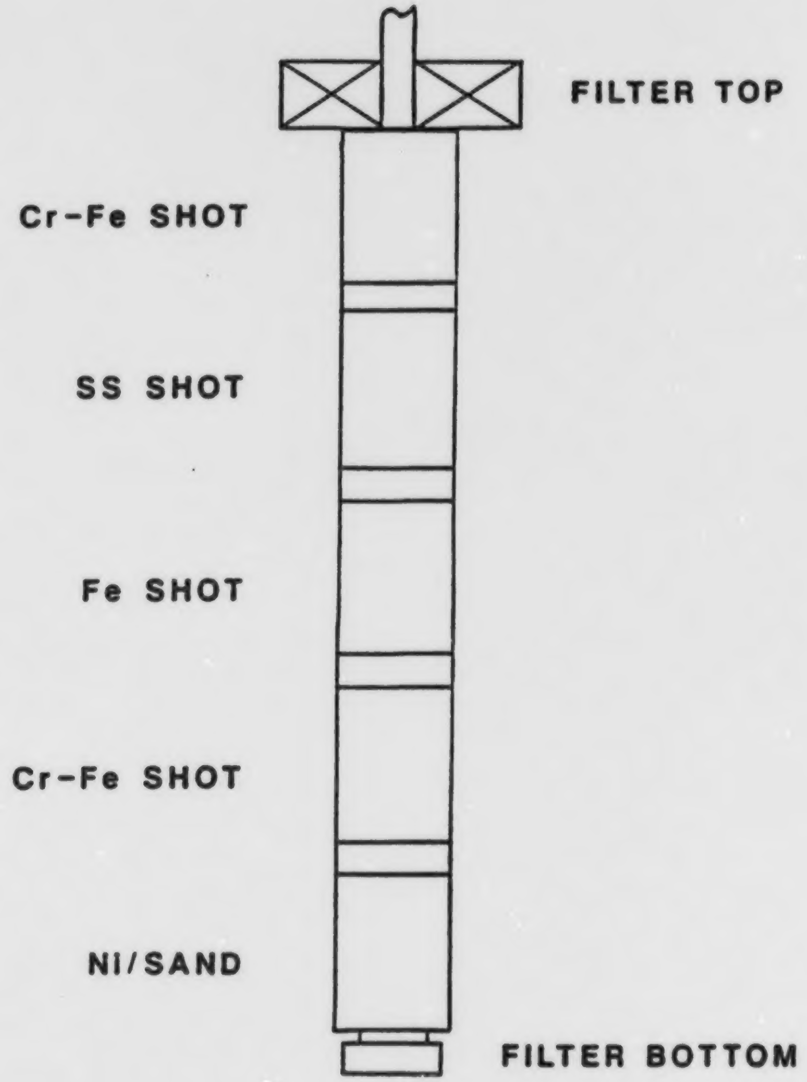

FILTER TOP
Cr-Fe SHOT
SS SHOT
Fe SHOT
Cr-Fe SHOT
NI/SAND
FILTER BOTTOM

Figure 6 (a)
Size Distribution at Various Depths - Texaco's Fort McMurray location

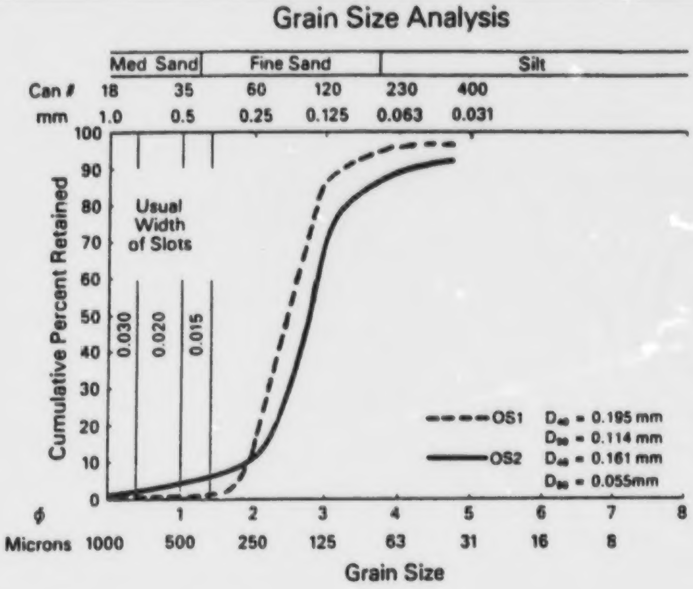


Figure 6 (b)
Sand Particle Size Distribution for UTF

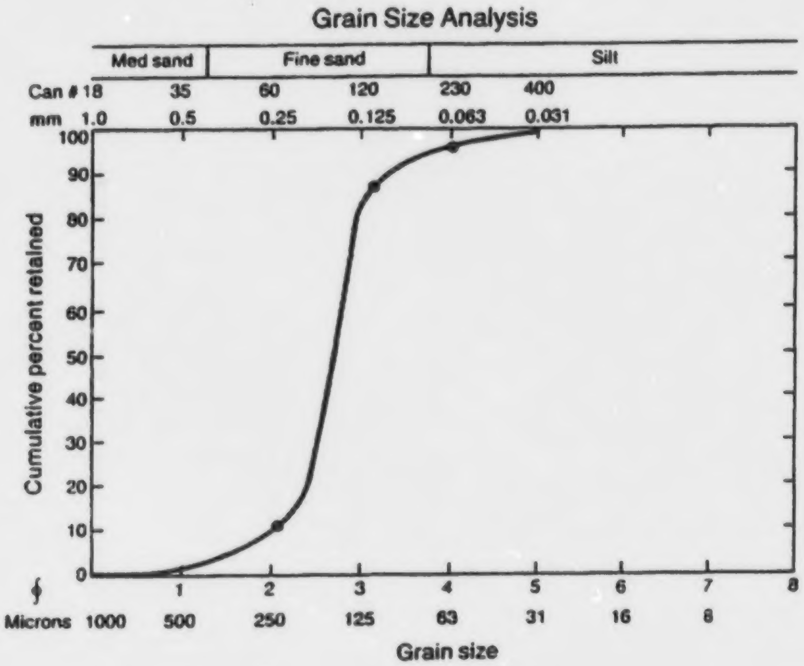


Figure 7
Permeability to Air of Various Filters Before and After Testing

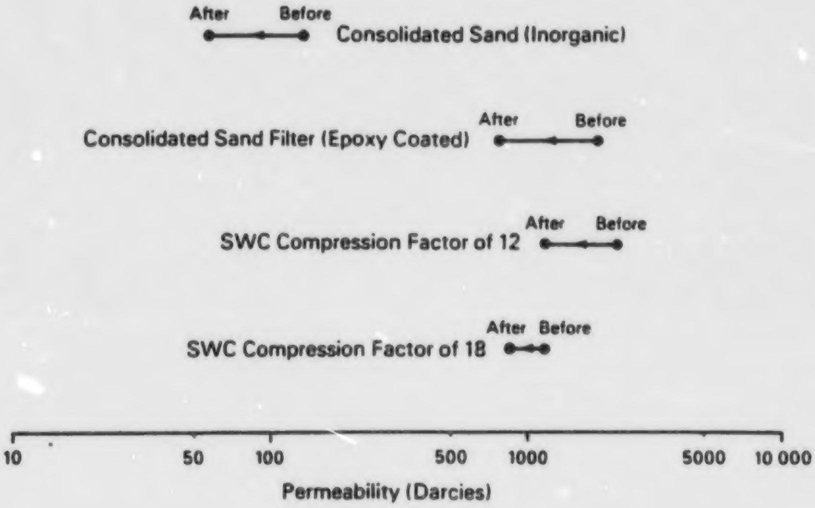


Figure 8
Schematic of SW Filter and the Two Ways of Solids Capture

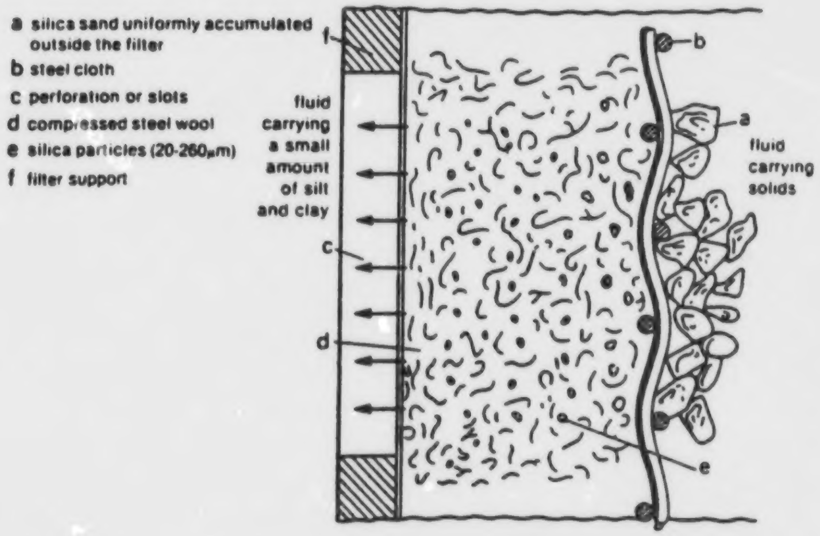

a silica sand uniformly accumulated outside the filter
b steel cloth
c perforation or slots
d compressed steel wool
e silica particles (20-260μm)
f filter support
fluid carrying a small amount of silt and clay
fluid carrying solids
a
b
c
d
e
f

Figure 9
Capture Efficiency in a Metallic Wool Filter (Calculated Data)

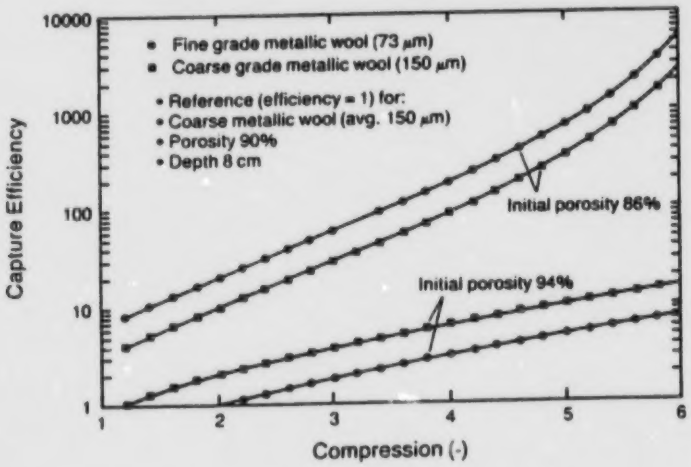


Figure 10
Efficiency of a Constant Depth SWC Filter

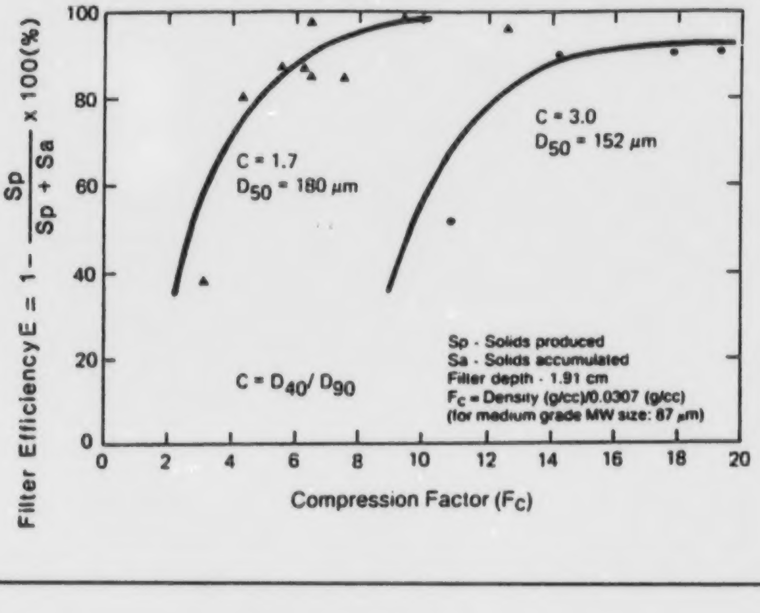


Figure 11
Results of Both Thermal and Non-Thermal Tests on Each Type of Filter. ***The results indicated filter choices as follows: 1. Total exclusion - Texaco-ARC and 0.005" wedge-wire screen. 2. Partial exclusion -*** **0.10" wedge-wire screen**

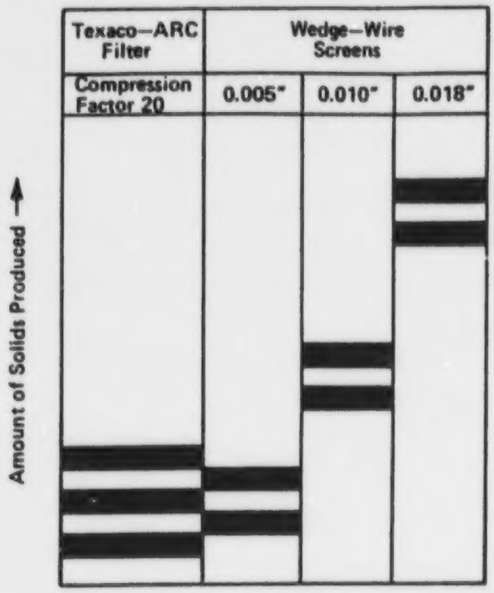


Figure 13
Downhole Completion Diagram - Texaco Canada Resources Athabasca Pilot Project (PI-5)

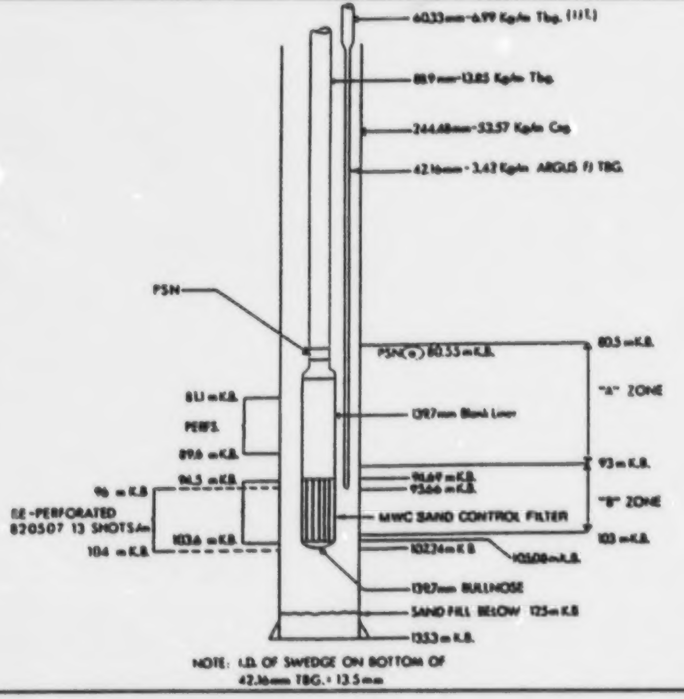
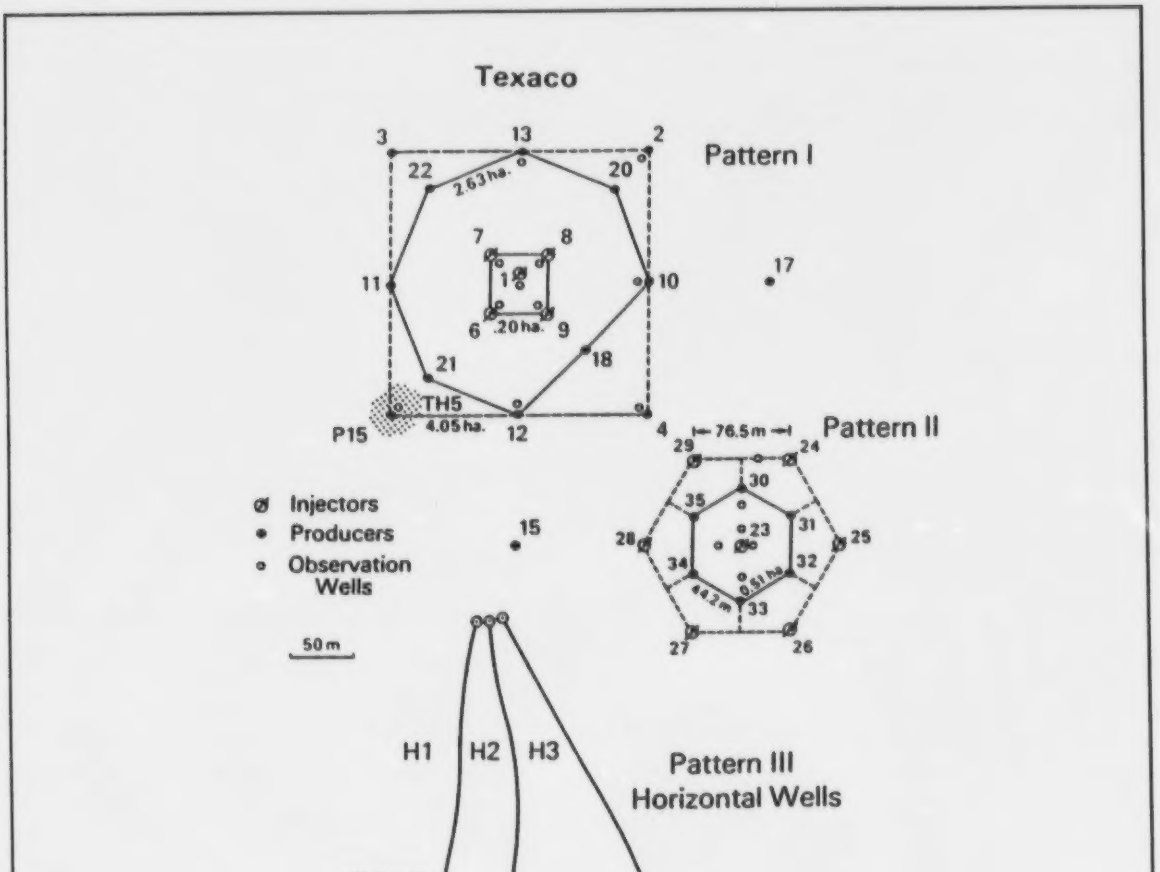

60.33mm-6.99 Kg/m Tbg. (1 1/2)
88.9mm-13.85 Kg/m Tbg.
244.48mm-53.57 Kg/m Csg.
42.16mm-3.42 Kg/m ARGUS FJ TBG.
PSN
PSN(e) 80.55 m K.B.
80.5 m K.B.
"A" ZONE
81.1 m K.B.
PERFS.
89.6 m K.B.
139.7mm Blank Liner
93 m K.B.
94.5 m K.B.
96 m K.B.
93.69 m K.B.
93.66 m K.B.
"B" ZONE
RE-PERFORATED 820507 13 SHOTS/m
MWC SAND CONTROL FILTER
103.6 m K.B.
103 m K.B.
104 m K.B.
102.24 m K.B.
105.08 m K.B.
139.7mm BULLNOSE
SAND FILL BELOW 125 m K.B.
135.3 m K.B.
NOTE: I.D. OF SWEDGE ON BOTTOM OF 42.16mm TBG. = 13.5mm

Figure 12
The Patterns of Texaco's Athabasca's Pilot Project


Texaco
Pattern I
3
13
2
22
20
2.63 ha.
7
8
1
11
10
17
6
.20 ha.
9
21
18
TH5
P15
4.05 ha.
12
4
Pattern II
76.5 m
29
24
30
35
31
23
28
25
34
32
0.51 ha.
44.2 m
33
27
26
Injectors
Producers
Observation Wells
15
50 m
H1
H2
H3
Pattern III
Horizontal Wells
236.5 mKB
260.7 mKB
280 mKB
559.8 mKB
591.7 mKB
629 mKB
80 m
120 m

26

HOT FLUID CIRCULATION IN WELLBORES

Ren Ying
The Petroleum Institute of Northeast China

ABSTRACT

Temperature distribution along wellbore is of significant importance to production of high wax, high pour point and viscous crude oil. Hot fluid circulation can increase crude oil temperature, improve its mobility and decrease pressure drop of fluid flow in a wellbore. This paper describes temperature distribution of crude oil and its influence on a flowing well, a beam pumping well and a hydraulic pumping well when hot fluid circulation is applied with the conventional production method. Pressure loss of a two-phase vertical flow, operating conditions of a viscous flowing well and critical pumping time of a beam pumping unit of a viscous well are discussed. Finally, results of hot fluid circulation in production wells are presented.

INTRODUCTION

In China, most of the viscous, high wax and high pour point oil is in deep reservoirs where high formation temperature and pressure are conducive to oil flow, and therefore supply of liquids to wellbores, especially during an early stage of production. One of the major difficulties in production of these reservoirs is related to heat loss along wellbore which leads to a significant increase in heavy oil viscosity, friction loss and the amount of wax solidification. The problem can sometimes be serious enough to plug off a wellbore. It can, however, be remedied by raising temperature of produced fluids and by reducing flow pressure loss using hot fluid circulation method.

In oil production, pressure loss of the two phase vertical flow in wellbores usually constitutes the major portion of the total loss in flow from reservoir to surface gathering and transportation systems. Although recent studies of two phase flow are numerous, they are mostly limited to isothermal conditions and constant fluid properties. This is in contrast to the dynamic conditions in a wellbore where fluid properties such as specific heat, density, viscosity and gas solubility vary along the wellbore due to heat loss, degassification and temperature and pressure drops. The change in viscosity is the most significant, sometimes exceeding two orders in magnitude. It is apparent that heating of a wellbore will affect fluid properties and flow behavior, and influence the conditions of a flowing well and the critical pumping time of a pumping well.

TEMPERATURE DISTRIBUTION ALONG A WELLBORE

When the wellbore is not heated, produced fluids undergo heat loss, degassification and gas expansion as they ascend from the bottom hole. In an analysis of fluids within a small element, dl, at the upper part of the wellbore, as shown in Figure 1, assuming that energy relieved with the degassification and gas expansion is balanced out with the energy consumed in lifting of gas and liquids, and that heat from wax solidification is uniformly distributed, the following equilibrium equation can be derived,

$$K_l \bullet [\theta - (t_o' - m \bullet l] \bullet dl + A \bullet (G_f + G_g) \bullet dl - \dot{q} \bullet dl = -W \bullet d\theta$$

Eqn (1)

At the bottom hole, $l=0$, $\theta = \tau_o'$. Solving the above equation leads to the following equation for wellbore temperature distribution,

$$\theta = \frac{W \cdot m + q - A \cdot (G_f + G_g)}{K_\ell} \cdot \left(1 - e^{-\frac{K_\ell}{W} \cdot \ell}\right) + (t_o' - m \cdot \ell)$$

Eqn (2)

As a matter of fact, wax solidification and fluids lifting affect temperature distribution very little and can be neglected. Therefore,

$$\theta = \frac{W \cdot m}{K_\ell} \cdot \left(1 - e^{-\frac{K_\ell}{W}}\right) + (t_o' - m \cdot \ell)$$

Eqn (2a)

MIXED HOT FLUID CIRCULATION

The mixed hot fluid circulation is classified into direct circulation and reverse circulation as illustrated in Figure 2. In the mixed reverse circulation, portion of the heated and degassed produced liquids is used to heat the tubing by circulating through the casing annulus. The circulating fluids enter the tubing at or above the bottom hole, mix with fluids from the reservoir and flow to the surface. The technique is suitable for flowing wells and pumping wells. Equations for the energy balance of the mixed reverse technique can be expressed as,

$$- W \, d\theta = K_{\ell 1} \cdot (T-\theta) \cdot d\ell$$

$$- W_2 \cdot dT = K_{\ell 2} \cdot (T-\theta) \cdot d\ell$$

$$+ K_{\ell 2} \cdot [T-(t_o - m \cdot \ell)] \cdot d\ell$$

Eqn (3)

The boundary conditions are: $T=T_i$ and T_f when $l=0$ and l_f respectively. Also, $W_1(t_o+ ml) + W_2 x T_f = W x \theta f$ and $W=W_1 + W_2$. Distributions of fluid temperature in tubing and casing annulus are obtained from Equation 3 and shown in Figure 3. Figure 4 shows the effect of circulation rate on the temperature distributions. The following observations can be made from the above figures.

- *i) Circulating liquid consumes lifting energy from the formation and takes up flowing capacity of the tubing. Production will be reduced if insufficient formation energy is available for fluids lifting.*

- *ii) At a low circulating rate, heating of fluids in the tubing is only effective within several hundred meters from the surface. By increasing circulating rate, heating effectiveness is increased but at the expense of increased liquid column in the annulus and bottom hole pressure. The flow of liquids from the formation to the wellbore becomes restricted as the pressure difference between the reservoir and wellbore is reduced. The problem can sometimes be serious enough to completely stop fluids from flowing to a flowing well while hot fluids are being circulated. The problem can be solved by installing an unidirectional valve above a packer in a pumping well,as shown in Figure 2b.*

The mixed direct circulation technique, as shown in Figure 2c is used mostly in a hydraulic pumping well where circulating liquids are also employed as working fluid for the pump. Energy balance equations for this method are,

$$- W_2 \cdot dT = K_{\ell 1} \cdot (T-\theta) \cdot d\ell$$

$$- W \cdot d\theta = K_{\ell 1} \cdot (T-\theta) \cdot d\ell$$

$$+ K_{\ell 2} \cdot [T-(t_o + m \cdot \ell)] \cdot d\ell$$

Eqn (4)

Boundary conditions are: $T=T_i$ when $\ell = 0$; when $l=lf$,

and $W=W_1+W_2$. By solving Equation 4, one can obtain temperature distribution of the circulating fluids in the tubing and the produced fluids in the annulus. It is worthwhile to mention that properties of the circulating fluids can affect the distribution of temperature of the produced fluids. Water is considered to be a poor circulating fluid because of its high convection heat transfer coefficient. Although its specific heat is twice that of oil, the large heat transfer rate of water limits the heating to within only several hundered meters from the surface leaving a large part of the wellbore unheated and cool. Wax solidification can be a problem with a high wax crude in an unheated section of the wellbore. In this case, high temperature of the produced fluids at the wellhead only present false sense of security of an impending problem. With oil as circulating fluids, the effectiveness is greater. This is clearly demonstrated in Figure 5 in whcih temperature distributions from circulating water and oil in a hydraulic pumping well are compared. Other advantages of circulating hot oil include improved lubrication, no corrosion and scaling and less oil/water separation problem at the surface. If produced oil with high wax content is used as circulating fluids, the hydrauslic pump must not be stopped to avoid the wax reservoirs with sufficient liquid flow. When flow is restricted due to decreasing formation pressure, hydraulic pumps become less effective, and the demand of wellbore heating is in conflict with the requirement of the circulating rate. Generally speaking, hydraulic pump is very ineffective in pumping heavy oil.

CLOSED HOT FLUID CIRCULATION

In this most adaptable wellbore heating method, hot circulating fluid does not come into contact with produced fluids, as shown in Figure 6. The method is applicable on flowing wells, pumping wells, high or low production wells with little or no loss in circulating fluid. Any low pour point and low viscosity fluid having no start-up difficulties such as diesel oil or water is suitable as a circulating fluid. The only disadvantage is its requirements for a rather complex wellbore completion and high capital cost. Assuming no gas expansion and wax solidification effects, the following energy balance equations can be derived,

$$t' = -\frac{K_{\ell 1}\cdot(t-\theta) + K_{\ell 2}\cdot(t-T)}{W_2} \qquad \text{Eqn (5a)}$$

$$T' = -\frac{K_{\ell 3}\cdot(t-T) - K_{\ell 3}\cdot[T-(t_o + m\cdot\ell)]}{W_3} \qquad \text{Eqn (5b)}$$

$$\theta' = -\frac{K_{\ell 1}\cdot(t-\theta)}{W_1} \qquad \text{Eqn (5c)}$$

Boundary conditions for the above equations can be written as,

$t=t_l$ when $l=0$

$t^f=T_f$ when $l=l_f$

and $\theta = t_o + m\bullet l_f$

Shown in Figure 7 are temperature distributions obtained by solving Equation (5) for a heavy oil producing well. By comparing produced fluid temperature distributions f-a curve with hot fluid circulation, with the distribution f-b curve from Equation (2) for the case without wellbore heating, wellhead temperatures between the two cases differ by as much as 25 times. This demonstrates the possibility of achieving reductions in fluid viscosity and flow resistance by wellbore heating.

Several factors, such as circulating medium and rate, influence the effectiveness of the close fluid heating method. Figure 8 shows that wellhead temperatures of produced fluids can be different at different circulating rate for the same diesel oil medium and initial temperature. Figure 9 indicates different temperature distributions from circulating fresh and thickened waters and diesel oil.

PRESSURE LOSS IN TWO PHASE VERTICAL FLOW AND CONDITIONS OF FLOWING WELLS

The methods to calculate gas-liquid slippage and friction loss are different according to different flow behaviour in two phase vertical flow,(Figure 10). From the momentum balance, the following equation expresses the total pressure gradient as the sum of the gradients of hydrostatic pressure, friction and acceleration[1,5,6],

$$\left(\frac{dP}{d\ell}\right)_t = \left(\frac{dP}{d\ell}\right)_{st} + \left(\frac{dP}{d\ell}\right)_f + \left(\frac{dP}{d\ell}\right)_{acc} \qquad \text{Eqn (6)}$$

The above equation can be recasted in a different form using liquid hydrostatic gradient , $\rho_L \bullet g/g_c$,

$G=G_{st} + G_f + G_{acc}$

The above equations are solved for pressure loss by the finite element technique taking into account changing fluid properties and flow behaviour along the wellbore. Hydrostatic pressure loss Gst can be expressed as,

$$G_{st} = \frac{\left(\frac{dP}{d\ell}\right)_{st}}{\rho_L \frac{g}{g_c}} = \frac{\rho_m}{\rho_L} \qquad \text{Eqn (8)}$$

where $\rho_m = \rho_L\cdot H_L + \rho_g\cdot(1-H_L)$

Eqn (8a)

and $G_{st} = H_L + \dfrac{\rho_g}{\rho_L}(1-H_L)$

Eqn (8b)

where ρ_g is gaseous density and ρ_L density of liquids which is related to the amount of solution gas in liquid under pressure. H_L is liquid hold-up which is related to viscosity and superficial velocity of gas and liquid, soluble gas, surface tension and slippage velocity. Hyrostatic Pressure drop calculated from the above equation is shown in Figure 11. Friction pressure loss Gf is given by the following equation,

$$G_f = 2 \cdot f_\omega \cdot \frac{V_{sL}^2 \cdot \rho_L \cdot (1+\frac{V_{sg}}{V_{sL}})}{d} \qquad \text{Eqn. (9)}$$

Friction coefficient fω in the above equation is related to Reynolds number Re, roughness coefficient e/d and gas/liquid ratio. The calculated friction loss is shown in Figure 12.

Pressure loss due to acceleration Gacc is important only in mist flow region and can be calculated from the following equation,

$$G_{acc} = (\rho_L \cdot V_{sL} + \rho_g \cdot V_{sg}) \cdot \frac{V_{sg}}{P} \cdot G \qquad \text{Eqn. (10)}$$

Total pressure drop G is expressed differently according to different flow regimes. For a bubble and plug flow, as shown in the flow regime map of Figure 10, G is given in Equation (11); for a mist flow, it is given in Equation 12, or

$$G = G_{st} + G_f \quad \text{(Flow regime I \& II)} \qquad \text{Eqn. (11)}$$

and

$$G = \frac{G_{st} + G_f}{1 - (\rho_L \cdot V_{sL} + \rho_g \cdot V_{sg}) \cdot \frac{V_{sg}}{P}} \quad \text{(Regime III)} \qquad \text{Eqn. (12)}$$

Total pressure gradient along the wellbore changes very little when no hot fluid is circulating because part of the hydrostatic pressure loss is compensated by the friction loss. With hot fluid circulating, total pressure gradient at the upper portion of the wellbore is significantly reduced due to lower fluid viscosity as shown in Figure 13. For a heavy oil production well, total pressure gradient is reduced mainly at the upper portion of wellbore by hot fluid circulation, especially by the closed fluid circulation technique. Figure 14 shows that, as production rate is increased, total pressure loss drops initially to a minimum value at production rate, Qc, before it increases with further increase in production rate. It also shows the dramatic decrease in total pressure drop due to hot fluid circulation and lower fluid viscosity. Operating conditions and production rate of a flowing well[7,10] is largely determined by bottom hole pressures. Lower bottom hole pressures allow more fluid to flow into the wellbore, yet the pressure must be high enough to overcome the total pressure loss and lift the produced fluids. A steady production is maintained when the condition of equilibrium is achieved in the wellbore. This condition is related to the operating point which is the point of interception of the total pressure loss versus production curve and the IPR curve, as shown in Figure 15. As a result of heating wellbore by fluid circulation, operating point of a well shifts from point A to point B, increasing production from 32.2 to 57 tons/day. Figure 16 shows a smaller increase in production from a different well, from 29 to 34.5 tons/day, because of poor fluid flow around the wellbore as indicated by the steeper IPR line.

HOT FLUID CIRCULATION ON HEAVY OIL PUMPING WELL

A common problem occurring to a viscous oil pumping well is that, due to high fluid viscosity, the downstroke motion of the pump rod lags behind the motion of the pump jack so that when the pump jack begins its up-stroke cycle, the pump rod has not reached the dead point. This reduces the effective stroke length of the plunger and lowers production rate. It can also break the pump rod due to high impact and stress at the upper end of the rod. This problem limits the pumping rate of a pumping well below a critical value, $(SN)_c$. At a critical pumping rate, the momentum of a pump rod in the wellbore is in equilibrium with its gravity force and friction force, or

$$P_r = P_{Lg} + P_{jf} + P_{gf} + P_{Vf} \qquad \text{Eqn (13)}$$

The P_{Lf}, P_{jf} and P_{Vf} terms in the above equation is a function of pumping rate, SN. Using finite element technique, Equation (13) is solved for critical pumping rate in a similar manner as Equation (6) is solved for pressure loss of a flowing well. The methods to calculate the various terms of Equation (13) are given in Reference [8] and [9]. Results from the calculation show the increases in critical pumping rate and production as a result of temperature increase and viscosity decrease by hot fluid circulation. For example, the critical pumping rate of a viscous oil well is 12.5 cycles per minute normally but increased to 63.2 after the well is circulated with hot fluid. If a pump with a 3.3 m stroke is used, critical pumping rate could be increased from 3.8 to 19.15 cycle per minute. However, oil production is eventually limited by fluid flow from the reservoir to wellbore. Also, the pumping rate of a rod pump is limited by yield strength of the materials used in the pumping equipment. Hot fluid circulation is helpful only when critical pumping rate is restricted by a very viscous fluid.

RESULTS FROM FIELD APPLICATION

Several hot fluid circulation techniques were tried at the fields. Results from these trials are summarized as follows,

- *i) The mixed fluid direct circulation method was tried at the hydraulic pumping wells of A1, A12, A73, A88, S13 and J3 in Liaohe oil field. The field tests involved heating the high pour point and high viscosity oil produced from these wells before circulating the oil to the wellbores. Results from these tests have been quite encouraging. Crude oil with pour point as high as 67° C had been produced with the technique. Because of better lubrication, the pumps lasted longer.*

- *ii) The close fluid circulation method was tested at high pour point flowing wells and pumping wells at the Liaohe oilfield. Results are summarized in*

- *iii) The close fluid circulation method was also tried at Liaohe G377 heavy oil well using hot water and thickened water as the circulating medium. Results are compared in Table 2. The well produced 0.2 ton/day of oil when circulating with hot water. Production jumped to 1.48 ton/day within 11 hours after the circulating medium was changed to thickened water. The test was discontinued due to poor production. However, the measured temperature distribution and the percentage increase in production can point to the merits of the method.*

CONCLUSIONS:

By heating wellbore to reduce fluid viscosity, pressure loss and well plugging, hot fluid circulation is found to be an effective production technique, especially for oil with high viscosity and high wax and asphalt contents. Theoretical analysis of the technique is in fairly good agreement with the results from field testings.

The different fluids circulation techniques discussed earlier are of different characteristics and should be selected according to reservoir and wellbore conditions and fluid properties. Recommendation are given in the following ranking order,

- *i) For a flowing well and beam pumping well producing either high pour point or viscous oil, the close fluid circulation technique using preferably diesel oil, or low pour point and non-viscous oil as a circulating medium is recommended. The technique allows easy start-up after production shut-in. Hot water in greater quantity can also be used as a circulating medium, but precautions must be taken to prevent corrosion and scaling problems. The mixed fluid circulation method can also be considered if low pour point and non viscous light oil is available locally, and quality of the light oil is not lowered by the fluid mixing.*

- *ii) For a high pour point oil well, particularly a deviated well, the mixed fluid direct circulation technique is recommended during high oil butlittle or no water production period. Oil produced from the well is heated and used as working medium for the hydraulic pump. Precaution must be taken to prevent production shut-in as start-up of the well may not be possible. For a heavy oil well, hydraulic pump is not recommended.*

- *iii) Hot fluid circulation techniques have only been tested at single wells with some success and are still at a preliminary experimental stage. Work must be continued to investigate any problem that may appear when the techniques are to be applied to a production system.*

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Notation

A	A=1/427 Kcal/Kg m
Gf,Gg	Liquid and gas flow rate, Kg/h
Kl	Liquid heat transfer coefficient, Kcal/m h °C
l	Longitudinal length of Wellbore, m
m	Temperature gradient of the formation, °C/m
H_L	Liquid hold-up
H_g	Gas hold-up
q	Heat intensity, Kcal/m h
t_o	Formation temperature at a certain depth, °C
t,T,	Fluid temperatures in inner annulus, outer annulus and production tubing.
W_1,W_2	Specific heat of produced fluids and cirulating fluid Kcal/h °C
V_{sL},V_{sg}	Liquid and gas superficial velocity, m/s
ρ_m,ρ_L	Density of produced fluids and liquid, Kg/m^3
(SN):	Pumping rate, m/min
S	Pumping stroke length, m
N	Pumping strokes/min

Table 1
Effect of Hot Fluid Circulating On Production

Well No	Well Type	Daily Production Rate, Ton/Day Conventional	Hot Fluid Circulation
J323	Flowing	0	24 - 28
J327	Flowing	0	15 - 13
J527	Flowing	0	40 - 50
A17	Pumping	0	40
A36	Pumping	0	10 - 12

Table 2
Temperature Distribution in Wellbore

Depth, m	Fresh Water Temp, C	Thickened Water Temp, C
50	96	92
100	89	89
200	76	83
300	68	79
400	61	75
500	55	70
600	51	68
700	48	66
800	46.5	64
900	46.5	62.5
1000	45	61.6
1100	45	60

Figure 1
Finite Element of a Wellbore for Energy Balance

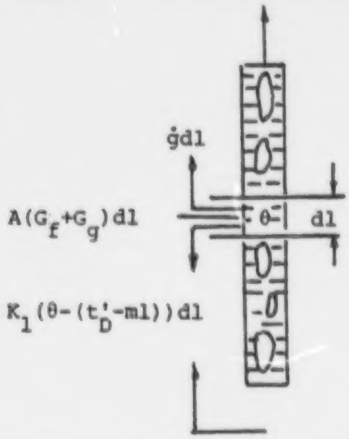

$\dot{q}dl$
$A(G_f+G_g)dl$
θ
dl
$K_1(\theta-(t_D'-ml))dl$

Figure 2
Mixed Hot Fluid Circulation Method

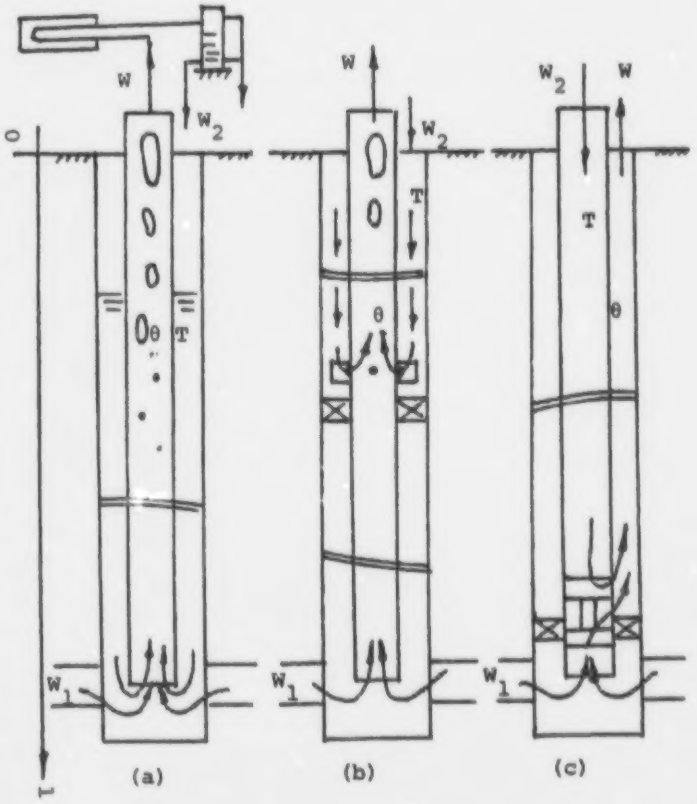

W
W_2
0
θ
T
W_1
l
(a)
W
W_2
T
θ
W_1
(b)
W_2
W
T
θ
W_1
(c)

Figure 3
Wellbore Fluid Temperature Distribution with Mixed Fluid Direct Circulation

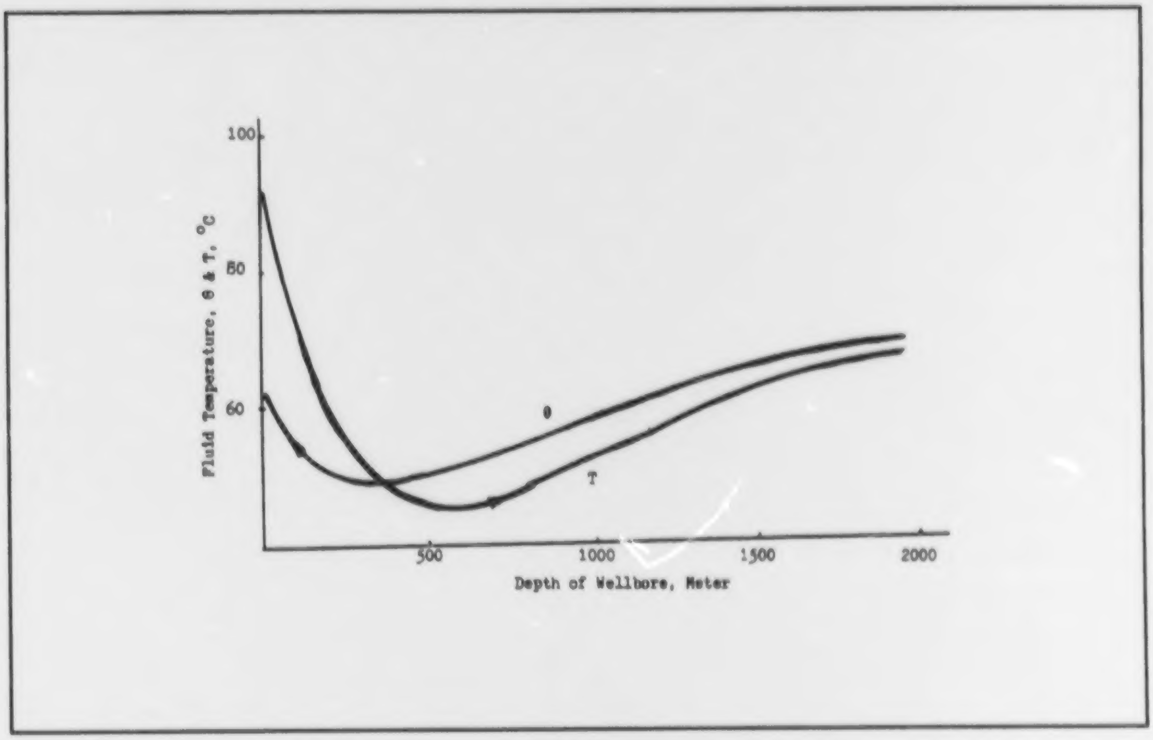


Figure 4
Effect of Circulating Rate on Wellbore Temperature Distribution Using Mixed Fluid Direct Circulation Method

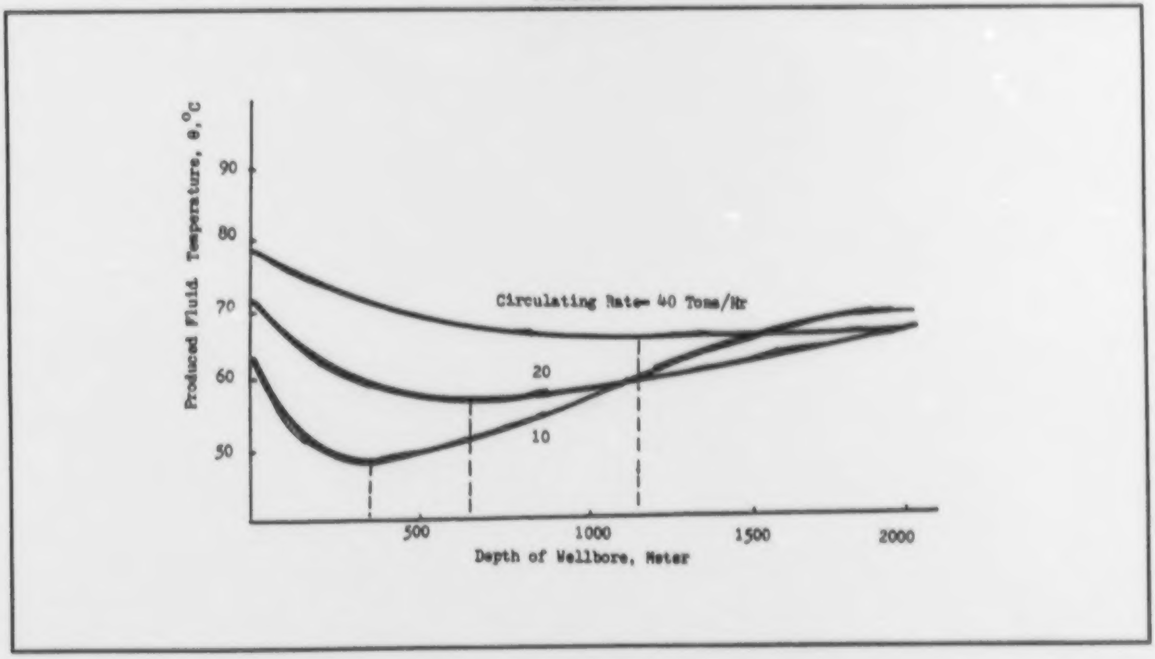


Figure 5
Effect of Circulating Medium on on Wellbore Temperature Distribution

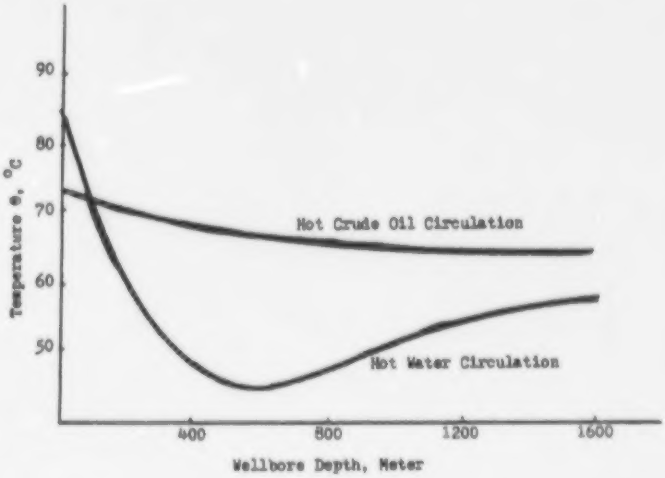


Figure 6
Wellbore Temperature Distribution with Closed Hot Fluid Circulating Method

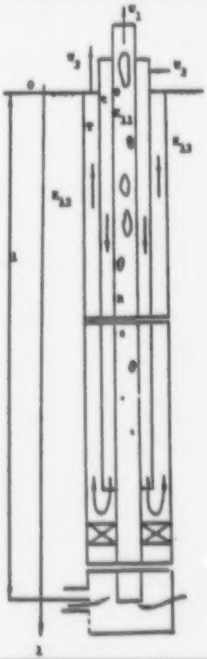


Figure 7
Wellbore Temperature Distribution with Closed Hot Fluid Circulating Method

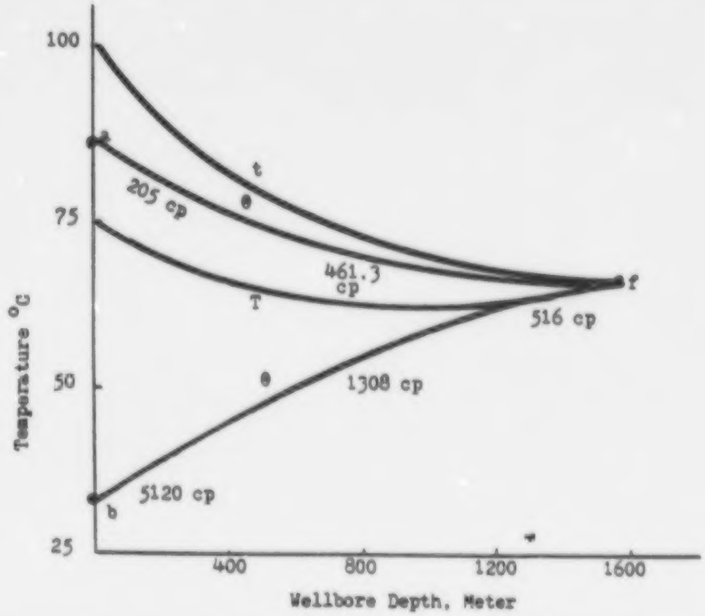


Figure 8
Effect of Circulating Rate on Temperature Distribution with Closed Hot Fluid Circulation Method

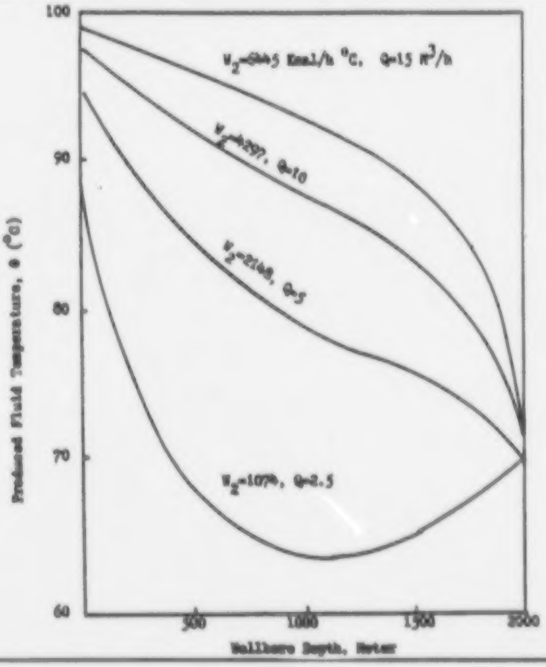


Figure 9
Produced Fluid Temperature Distribution Using Waters and Oil as Circulating Medium

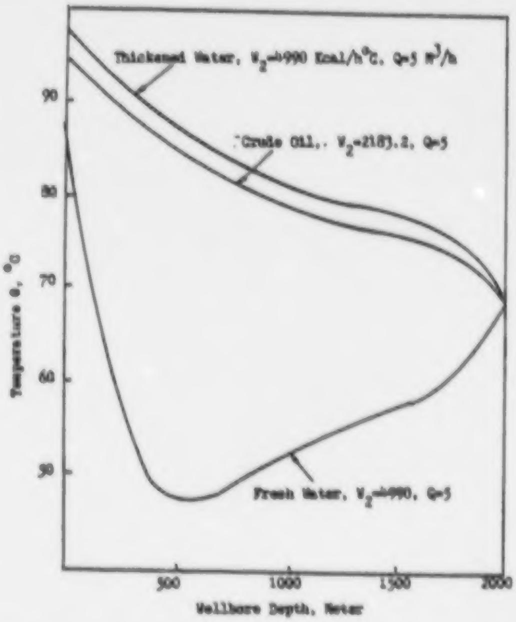


Figure 10
ROS Flow Regime Map in Two Phase Vertical Flow

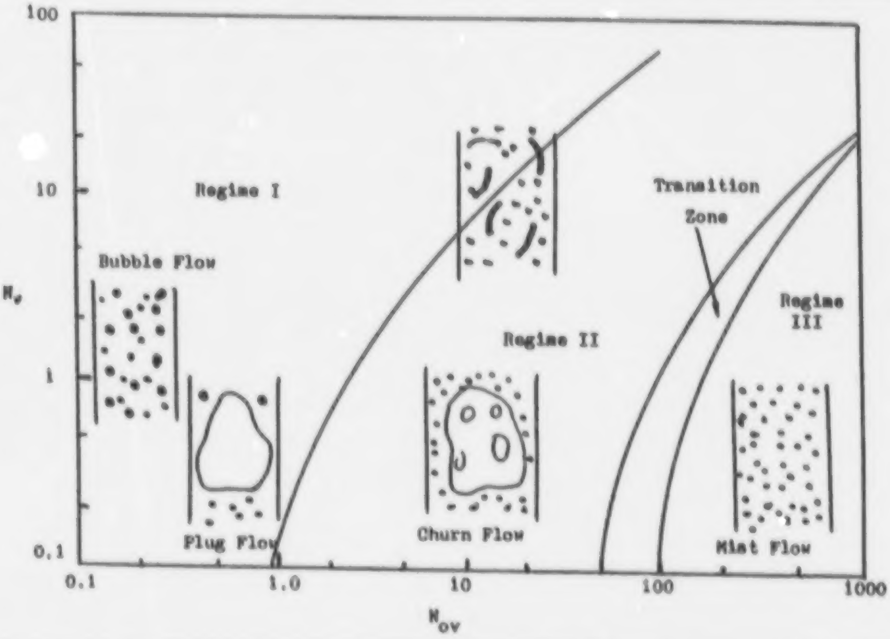


Figure 11
Hydrostatic Pressure Drop at Various Wellbore Depth

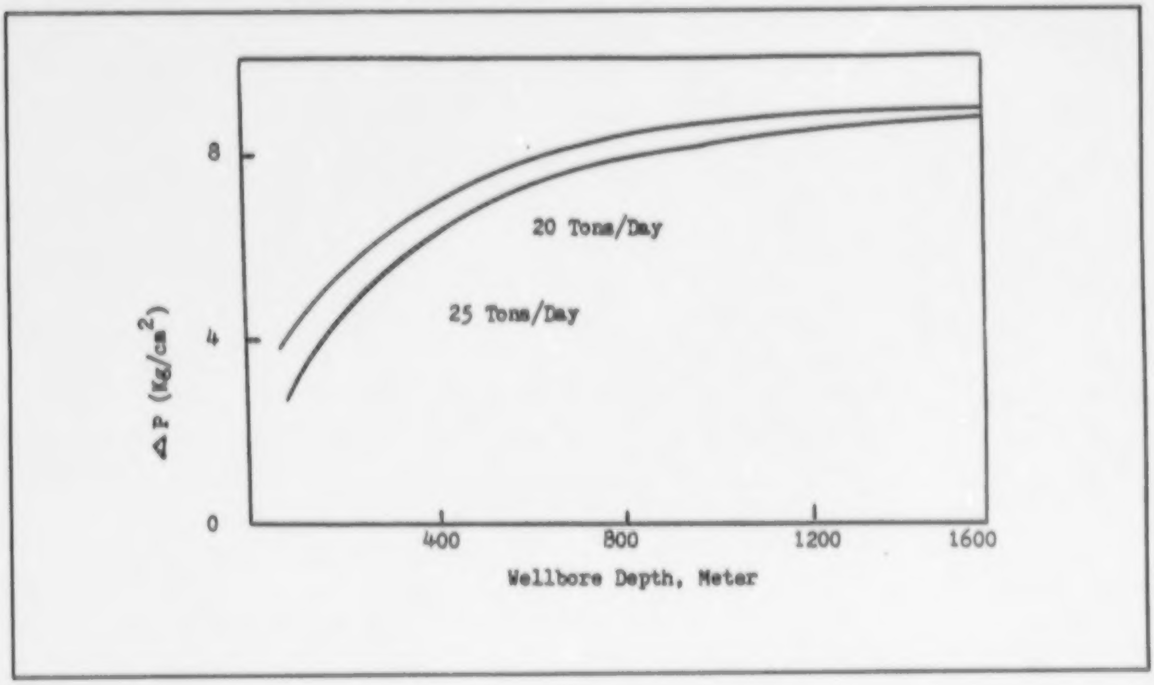


Figure 12
Distribution of Friction Loss Along Wellbore

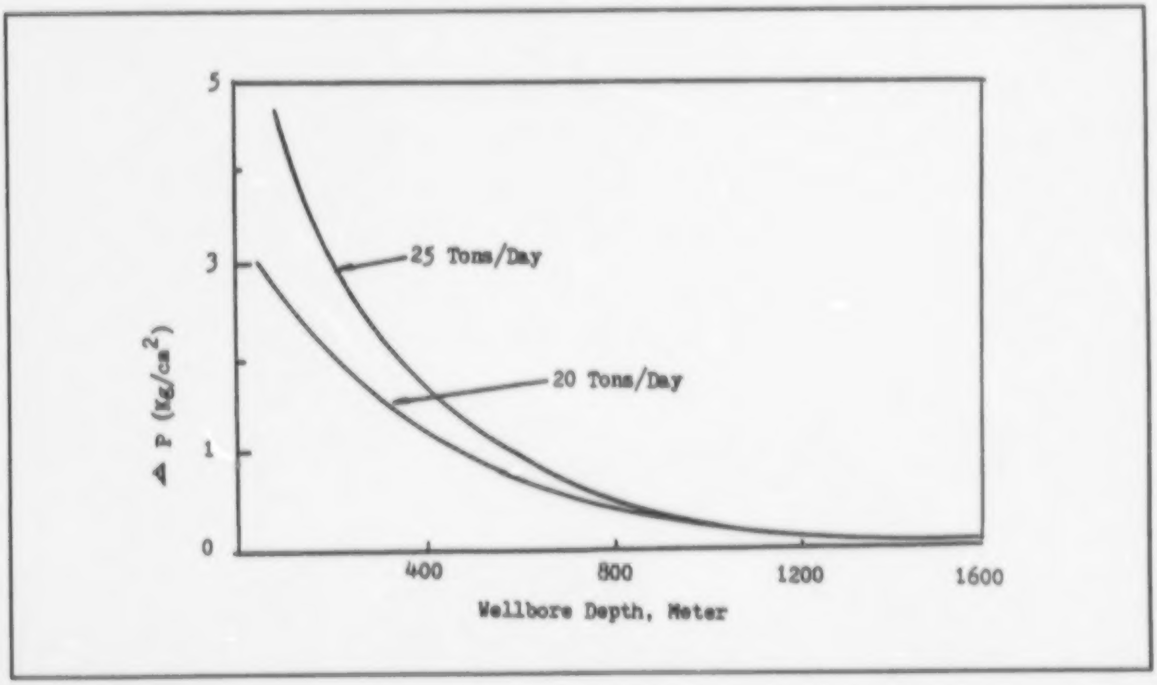


Figure 13
Total Pressure Loss With and Without Hot Fluid Circulation

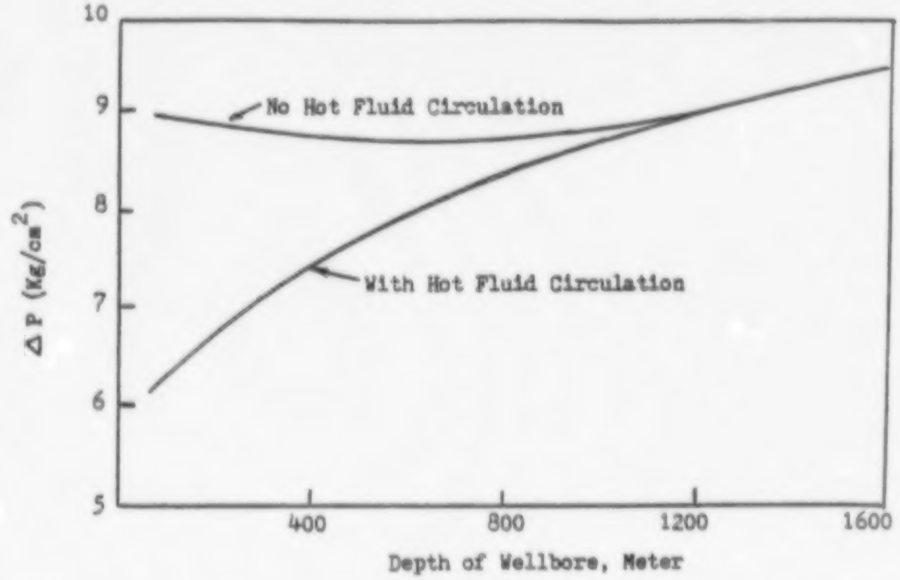


Figure 14
Total Pressure Loss as a Function of Production Rate

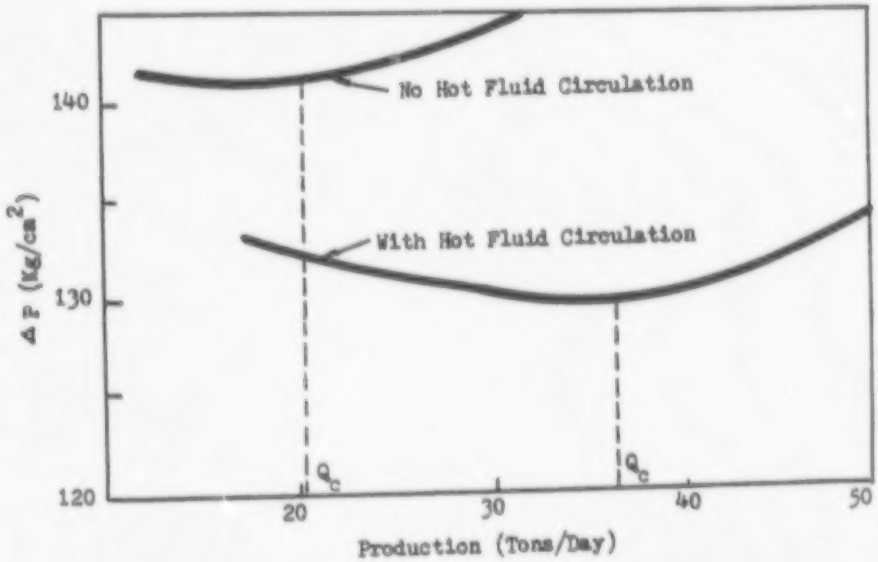


Figure 15
Operating Point of Well A With and Without Hot Fluid Circulation

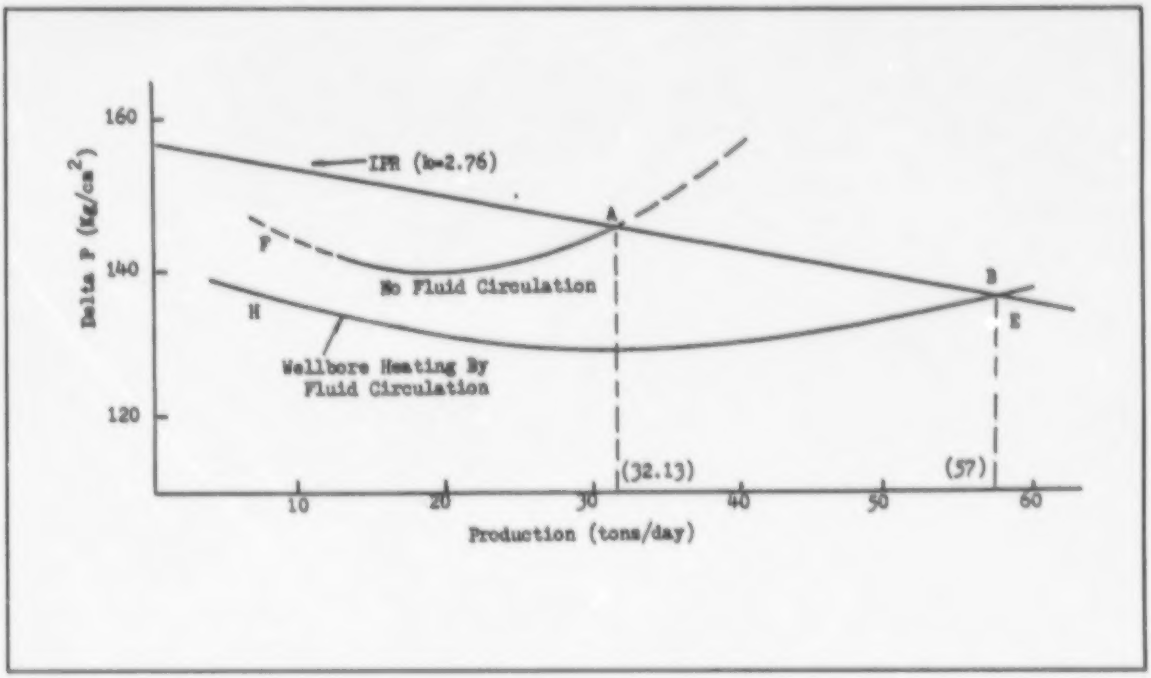
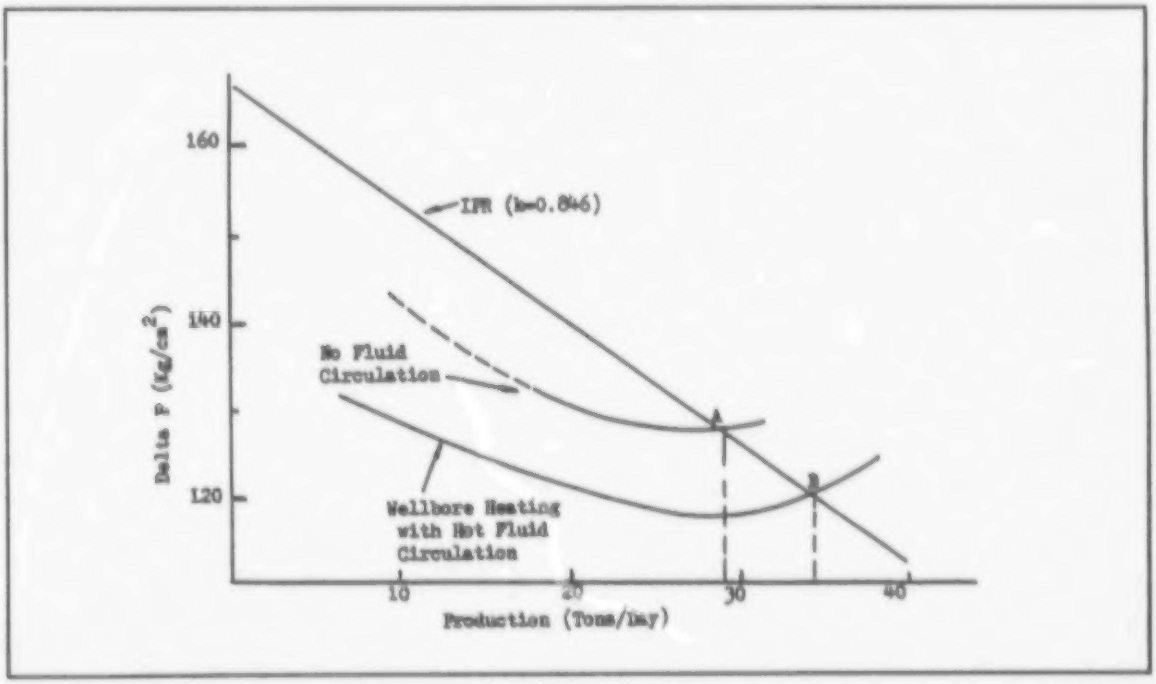


Figure 16
Operating Point of Well B With and Without Hot Fluid Circulation



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AN IMPLICIT TREATMENT OF WELLBORE PRESSURE IN THERMAL RESERVOIR SIMULATOR

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ABSTRACT

In the thermal simulation for field scale, one always uses more than one injector and one producer. To be consistent with the simulator which was an implicit simulator, a fully implicit method was developed for the wellbore pressure treatment. An example was used to demonstrate the technique which improved the numerical stability and calculation efficiency.

INTRODUCTION

Thermal simulation requires one to solve a set of higher order nonlinear partial differential equation. These equations include the conservation of mass, the momentum equations and the conservation of energy for components, such as water and hydrocarbons. They are used to represent the physical process in the reservoir during the steam simulation and they are solved by a fully implicit difference scheme in terms of space and time. The Newton's iteration technique was used to solve this set of equations. The detail of solution technique was given by Coats(1) paper.

In the thermal simulation for field scale, more than one injector and one producer was used. But the Coats' paper solved the wellbore pressure explicitly. Our field experience showed that the wellbore pressure increased sharply, especially at the initial steam injection and the initial production period. However the simulator did not give the same order of magnitude as the field data. This is due to the wellbore pressure which was solved explicitly. To be consistent with the simulator, a fully implicit solution algorithm was developed.

By solving the wellbore pressure implicitly, the previous band matrix can not be maintained. That is, the Newton's iteration technique can not be used. Hence it increases the difficulty to solve the matrix. This paper is to address this problem.

In this paper, we also give an example to show that a direct solution technique is more efficient than the iteration technique for the number of grid blocks greater than four hundred. The solution algorithm also can be extended easily to incomplete elimination as preconditioning for generalized conjugate gradient acceleration.

MODEL DESCRIPTION

This model is based upon Coats' formulation, except that the wellbore pressure is solved implicitly. The basic equations, conservation of mass, momentum equations and the energy equation for components are the same as Coats as follows:

Conservation equation

$$\frac{V}{W t} \bar{w} \left(d \sum_{j=1}^{N_p} p_j S_j X_{ij}\right) = \sum_{j=o,g,w} W T p_j X_{ij} \frac{K_{rj}}{)_j} \left(Wp + Wp_{cj} - q_j WZ\right) - q_i, \quad i = 1, 2, \ldots, N_c \tag{1}$$

Energy equation

$$\frac{V}{W t} \bar{w} \left[d \sum_{j=1}^{N_p} p_j S_j U_j + (1 - d) M_f (T - T_i)\right] = \sum_{j=o,g,w} W \left[T p_j \frac{K_{rj}}{)_j} H_j \left(Wp + Wp_{cj} - r_j WZ\right)\right] + W \left[t_c WT\right] - Q_H - Q_{HL} \tag{2}$$

Saturation constraint

$$\sum_{j=1}^{N_p} wS_j = 0 \tag{3}$$

Molar fraction constraints

$$\sum_{i=1}^{N_c} x_{ij} = 1.0 \qquad j=1,\ 2,\ \ldots,\ N_p \tag{4}$$

The above set of equations is a nonlinear partial differential equation for unsteady state. According to Coats, a fully implicit finite difference scheme was used, then an iteration solution algorithm was adopted to eliminate the space dependence in every time step. A set of linear equations is solved in iteration for variables wP, wT and saturation wSi. There are three to ten variables in every grid block.

The proposed new model is to improve the Coats well model. Along the wellbore in the vertical direction, a finite layer is used to calculate the flow rate. At k layer for component i is:

$$q_{ik} = WI_k\, g_{ik}\,(p_k - p_{wfk}) \tag{5}$$

where WI_k is production index; g_{ik} is mobility ratio; p_k is the grid block pressure at layer k; P_{wfk} is the well pressure at layer k and it refers to the reference point, ie, the wellbore pressure:

$$P_{wfk} = P_{wf} + pWZ \tag{6}$$

For general purposes, we have to consider two cases; one is constant pressure and the other is constant flow rate. If the wellbore pressure is given, then there is no need to use the fully implicit technique and Coats model is adequate. On the other hand, for a given flow rate, the following procedure should be used.

If the production rate per well is given, using equations (5) and (6), the production rate for k layer is:

$$q_{ok} = WI_k \quad g_{ok}(p_k - p_{wfk} - \bar{p}WZ)$$

$$\cong q_{ok}^{l} + \sum_{m=1}^{NE} \frac{\delta q_{ok}}{\delta p_{mk}}\, \delta p_{mk} + \frac{\delta q_{ok}}{\delta p_{wf}}\, \delta p_{wf} \tag{7}$$

where P_m is a variable, similar to w_P, w_T and wS_w, to be solved in the matrix. NE is the number of variables for a grid block and 1 is the latest iterate solution. Since the production rate is known, hence we have

$$\sum_k q_{ok} = \sum_k q_{ok}^{l} = qo \tag{8}$$

from equation (8), there is an additional constraint equation

$$\sum_k \left\{\frac{\delta q_{ok}}{\delta p_{mk}}\, \delta p_{mk} + \frac{\delta q_{ok}}{\delta p_{wf}}\, \delta p_{wf}\right\} = 0 \tag{9}$$

If the total flow rate is given, equation (9) becomes

$$\sum_{l=o,g,w} \sum \left\{\frac{\delta q_{lk}}{\delta p_{mk}}\, \delta p_{mk} + \frac{\delta q_{lk}}{\delta p_{wf}}\, \delta p_{wf}\right\} = 0 \tag{10}$$

Now, there are N number of grid blocks in the model, NE number of unknowns for each grid block, and NW number of wells. Hence the number of total equations

is:

$$NT = N * NE + NW \tag{11}$$

The number of unknowns is also N * NE + NW, hence the problem is well defined.

SOLUTION OF THE BORDERED MATRIX

Let us look at a simple example, as shown in Figure 1. The reservoir formation is divided into 3 X 2 X 2 grids. Using D4 ordering (red/black), the number of the grid for each layer is given in Figure 2. This creates a bordered (unbanded) matrix. Where x is a non-zero block which contians NE * NE elements in every block. The blank is zero block.

Hence, with respect to the fully implicit treatment of the wellbore pressure, one has to solve the following matrix in every Newtonian iteration of every time step.

$$\begin{pmatrix} A & W_1 \\ W_2 & W \end{pmatrix} \begin{pmatrix} x_1 \\ x_2 \end{pmatrix} = \begin{pmatrix} b_1 \\ b_2 \end{pmatrix}.$$

(12)

where A is a matrix which consists of the unknowns from basic equations for every grid block, and is a banded matrix. W1, W2 and W are matrices which are introduced by the unknown wellbore presaure. It is not practical to simply use the iteration technique since it would requir a large amount of computer memory and CPU time. Hence it is desirable to find a better solution technique. This paper introduces a new direct solution technique. Even though the iteration technique is well developed nowadays, the direct solution technique is still quite accurate and more efficient for a medium or small thermal simulator which is less than 300 grid blocks.

As shown in Figure 3, Equation (13) can be written as follows:

$$\begin{pmatrix} D_1 & B_1 & W_{11} \\ B_2 & D_2 & W_{12} \\ W_{21} & W_{22} & W \end{pmatrix} \begin{pmatrix} x_{11} \\ x_{12} \\ x_2 \end{pmatrix} = \begin{pmatrix} b_{11} \\ b_{12} \\ b_2 \end{pmatrix} \tag{13}$$

Matrix a is as follows:

$$\begin{pmatrix} D_1 & B_1 \\ B_2 & D_2 \end{pmatrix} \tag{14}$$

This is a symmetric in numerical value. Even though the numerical value is not symmetric, the matrix is symmetric. D_1 and D_2 are nonsingular, W_1 and W_2 can be expressed with W_{11}, W_{12}, W_2 and W_{22}.

Transform Eq. (13) by mutiplying both sides by

$$\begin{pmatrix} D_1^{-1} & & \\ & D_2^{-1} & \\ & & I \end{pmatrix} \text{, then}$$

$$\begin{pmatrix} I_1 & B_4 & \bar{W}_{11} \\ B_3 & I_2 & \bar{W}_{12} \\ W_{21} & W_{22} & W \end{pmatrix} \begin{pmatrix} x_{11} \\ x_{12} \\ x_2 \end{pmatrix} = \begin{pmatrix} \bar{b}_{11} \\ \bar{b}_{12} \\ b_2 \end{pmatrix} \tag{15}$$

where

$$B_3 = D_2^{-1} B_2,\ B_4 = D_1^{-1} B_1,\ \bar{W}_{11} = D_1^{-1} W_{11},\ \bar{b}_{11} = D_1^{-1} b_{11}$$
$$\bar{W}_{12} = D_2^{1} W_{12},\ \bar{b}_{12} = D_2^{1} b_{12} \tag{16}$$

Again Eq. (15) multiply by

$$\begin{pmatrix} I_1 & 0 & 0 \\ -B_3 & I_2 & 0 \\ -W_{21} & 0 & I_3 \end{pmatrix} \tag{17}$$

One obtains:

$$\begin{pmatrix} I_1 & B_4 & \bar{W}_{11} \\ 0 & M_2 & \bar{\bar{W}}_{12} \\ 0 & \bar{W}_{22} & \bar{W} \end{pmatrix} \begin{pmatrix} x_{11} \\ x_{12} \\ x_2 \end{pmatrix} = \begin{pmatrix} \bar{b}_{11} \\ \bar{\bar{b}}_{12} \\ \bar{b}_2 \end{pmatrix} \tag{18}$$

Where

$$M = I_2 - B_3B_4,\ \bar{\bar{W}}_{12} = \bar{W}_{12} - B_3\bar{W}_{12},\ \bar{W}_{22} = W_{22} - W_{21} B_4$$
$$\bar{W} = W - W_{21}\bar{b}_{11},\ \bar{\bar{b}}_{12} = \bar{b}_{12} - B_3\bar{b}_{11},\ \bar{b}_2 = b_2 - W_{21}\bar{b}_{11}$$

(19)

From Eq. (17), we have

$$X_1 = b_{11} - B_4 X_2 - W_{11} X_2 \tag{20}$$

and

$$\begin{pmatrix} M & \bar{\bar{W}}_{12} \\ \bar{W}_{22} & \bar{W} \end{pmatrix} \begin{pmatrix} x_2 \\ x_3 \end{pmatrix} = \begin{pmatrix} \bar{\bar{b}}_2 \\ \bar{b}_2 \end{pmatrix} \tag{21}$$

Eq. (21) multiply by $\begin{pmatrix} M^{-1} & 0 \\ -\bar{W}_{22}M_1^{-1} & I \end{pmatrix}$

one obtains

$$\begin{pmatrix} I & F \\ 0 & G \end{pmatrix} \begin{pmatrix} x_2 \\ x_3 \end{pmatrix} = \begin{pmatrix} h_2 \\ h_3 \end{pmatrix} \tag{22}$$

Where

$$F = M\bar{\bar{W}}_{12},\quad h_2 = M^{-1}\bar{\bar{b}}_{12}$$
$$G = \bar{W} - \bar{W}_{22} M_1^{-1}\bar{\bar{W}}_{12},$$
$$h_3 = \bar{b}_2 - \bar{W}_{22} M \bar{b}_{12} = \bar{b}_2 - \bar{W}_{22}h_2 \tag{23}$$

From Eq. (22), we havel

$$Gx_3 = h_3 \tag{24}$$

$$x_2 = h_2 - Fx_3 \tag{25}$$

Based upon the above analysis, the following procedure can be used to solve the matrix Eq. (13):

(a) Using D_4 ordering to number the grid blocks for each layer, solve Eq. (13) for n_1, n_2 and n_3 vectors where n_1 is the upper portion of D_4 ordering, n_2 is the lower portion of D_4 ordering, and n_3 is the number of wells.

(b) A unit coefficient matrix is formed in upper portion of D4 ordering for the formation grid blocks and the right hand side terms $[(D_1)_i, (B_1)_i, (W_{11})_i, (b_{11})_i]$.

(c) Using Crout factoring method for the above matrics, we obtain I_i, W_{11i} B_{4i}, and b_{11i}.

(d) Repeat steps (b) to (c), we get the whole matrics I, B_4, W_{11}, and b_{11}.

(e) Using D_4 ordering to number the grid blocks for the lower portion of the formation, we obtain matrics B_{2i}, D_{2i}, W_{12i} b_{12i}. Using Crout factoring method, we form matrics B_{3i}, I_i, W_{12i} and b_{12i}.

(f). Mutiply B_i, with the matrix obtained from step (d), and using Eq. (19), we obtain M, W_{12}, and b_{12}.

(g). Repeat Steps (e) and (f), we get the whole matrics M, W_{12} and b_{12}.

(h) In the augmented matrices, M, W_{12}, and b_{12}, we considered M as a coefficient matrix, and W12 and b_{12} as multi-right-hand-side vectors. Using Gaussian elimination, we obtain $F_2 = M^{-1}W_{12}$, and $h_2 = M^{-1}b_{12}$.

(i) Using Eq. (9) or (10), we obtian row vectors $[(W_{21})_i, (W_{22})_i, W_i\ (b_2)_i]$.

(j) Execute Eq. (19), we obtain well equation for W_{22}, b_2 and W.

(k) Repeat steps (i) and (j), form the whole matrics W22, b2 and W.

(l) Using Eq. (23), solve G and h_3.

(m) Using Gaussian elimination, solve X_3 from Eq. (24).

(n) From Eq. (25), solve for X2.

(o) From Eq. (20), solve for X_1.

Hence X_1, X_2 and X_3 are solved.

From the procedure described above, there is only a little calculation in every step, except step (h) in which it is required to solve more unknowns. Even though we have to pay more attention to the fact that the coefficient matrix formed in step (h) is a full matrix, the number of unknowns is the same as the number of wells. Generally speaking, the number of unknowns is small, hence the calculation is not difficult.

We also should pay attention to the fact that in the whole calculation procedure, we just need to store matrices B_4, W_{11} and b_{11} formed in step (d) and M, W_{12} and b_{12} formed in step (g) by using compression form. The coefficient matrix formed from the lower portion of D_4 ordering don't need to be stored. Hence the storage requirement is small.

TEST PROBLEM:

In this section, examples are given for the cyclic steam and the steamflood. Comparison of CPU time is done between the explicit and implicit treatment for wellbore pressure on ELXSI computer.

1. Single Well example

The reservoir is heterogeneous and a radial model (or cylindrical coordinate) is used.

Well radius is 0.1 meters, and the total radial length is 80.2 meters.

13 grids are used in the R-direction. Block boundaries are 0.1, 0.91, 3.96, 7.01, 10.06, 13.1, 16.15, 19.2, 22.25, 25.3, 28.35, 31.39, 43.59, and 80.2 meters.

In the vertical direction or Z-direction, 4 grids are used and the distances from the top are 0.0, 3.05, 9.10, 16.76, and 24.38 meters.

Depth of the formation is 457.2 meters from the surface.

Rock Properties:

Horizontal permeabilities from the top layer are 2000, 500, 1000, and 2000 mD.

The ratio of vertical permeability to the horizontal permeability is 1/2.

The porosity is constant at 0.3.

Thermal conductivity of the rock is constant at 1.73 W/M*K.

Heat capacity of the rock is constant at 2347 KJ/K*cu M.

Effective rock compressibility is 0.00725 /bar.

Oil properties:

Density at stand condition = 972 kg/cu M.

Compressibility = $7.25\ e^{-5}$ /bar

Coefficient of thermal expansion = $6.84\ e^{-4}$ /K.

Specific heat = 2.0934 KJ/kg*k.

Molecular weight = 600

Viscosity Table

Temperature (C)	Viscosity (cp)
23.9	5780.
37.8	1380.
65.6	1870.
93.3	47.0
21.1	17.4
148.9	8.5
176.0	5.2
260.0	2.5

Initial Condition:

Oil saturation = 55 %.

Water saturation = 45 %.

Reservoir temperature = 51.7° C

Pressure at the center of the top layer = 5.17 bar.

Pressure distribution according to gravity, no capillary pressure, Pc=0.

Operating Condition:

Perforated all layers.

The first cycle lasts for 365 days, the steam injection for 10 days, soaking for 7 days, and then produced for 348 days.

Steam injection pressure is 22 bar and the quality is 70 %. The maximum injection rate is 159 ton/day (cold water equivalent) and the maximum injection pressure is 69 bar.

The minimum production pressure is 1.17 bar, and the maximum production rate is 159 tons/day.

■ 2. Example of nine-point steam drive pattern

The total area of the pattern is 10116.75 square meters. The location of the wells are shown in Figure 4. The fluid and rock properties and initial conditions are the same as Example 1.

Operating condition:

Perforated only at the bottom layer

The maximum injection pressure is 69 bar and the maximum injection rate is 47.7 tons/day.

The minimum production pressure is 1.17 bar and the maximum production rate is 159 tons/day. The maximum steam produced is 1.5 tons/day.

10 years simulation was completed.

Explicit and implicit methods for wellbore pressure were applied to the above two examples. The calculated physical properties and the cumulative production indicated that the numerical difference was within 2 %. However, as shown in Table I, the CPU time is quite different. Note that the automatic time step control was used for both methods and the maximum change of saturation was used for time step control. From Table I, the CPU time for implicit wellbore pressure method is less than the explicit method, at about 80 % for same time step. The explicit method diverged when 15 % saturation change control, but the implicit method had no problem to get to the solution. This indicates the superiority of the implicit method.

CONCLUSION

A fully implicit thermal simulator was developed. The model is fully implicit; not only pressure, temperature, and saturation but also the wellbore pressure. Thus a solution algorithm was also developed to solve this bordered matrix.

This implicit treatment of wellbore pressure improves the numerical stability, reduces the number of time steps and reduces the CPU time by 20 %.

The solution algorithm can be extended easily to iterative method.

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Table 1

Comparison of Time Step Size

Cummulative Number of Time Steps

Time-step	Cyclic Steam		Steamflood	
Control(%)	Explicit	Implicit	Explicit	Implicit
5.0	144	120	430	342
10.0	111	98	360	293
15.0	/	70	/	262

Figure 1

Division of Reservoir Grid Block

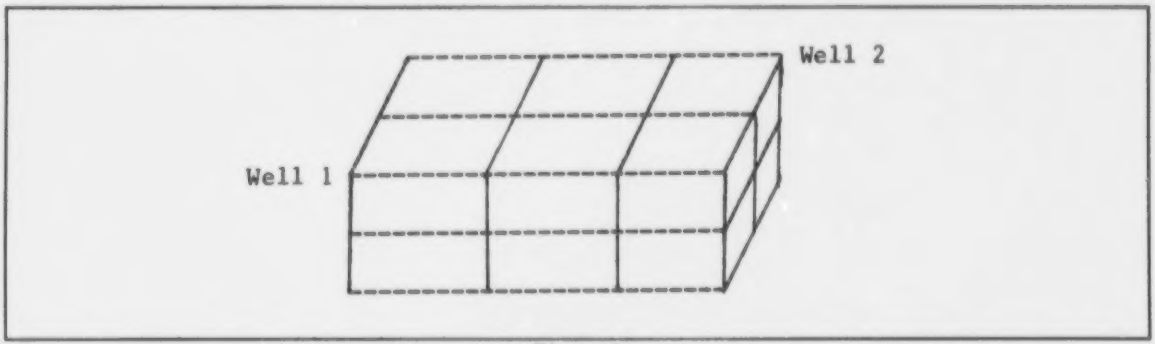
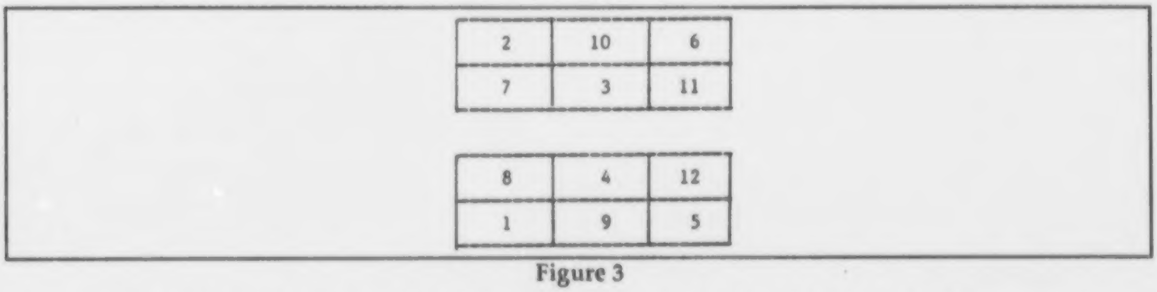


Figure 2

D4 Ordering 3*2*2

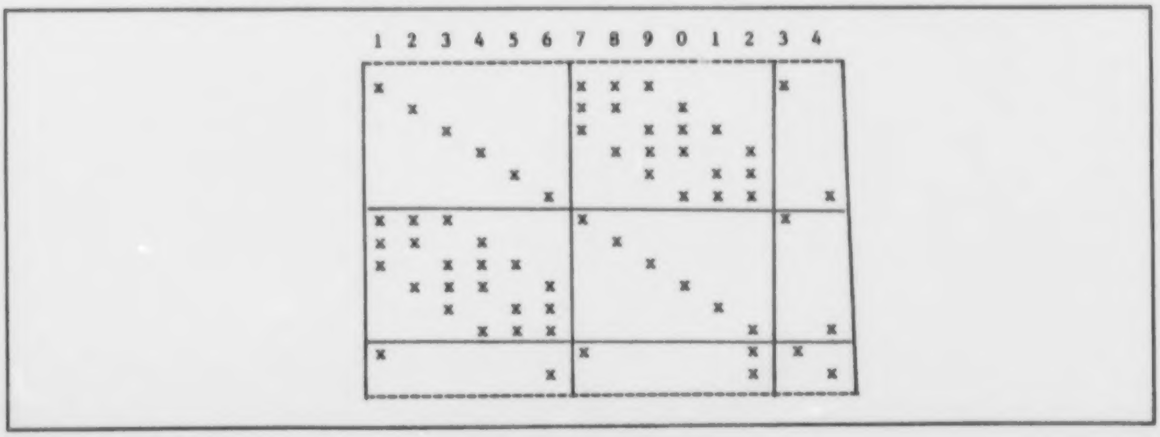


2	10	6
7	3	11

8	4	12
1	9	5

Figure 3

Bordered Jacobian System Produced by Fully Coupled Multi-block Well



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HEAVY OIL PRODUCTION SYSTEMS

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ABSTRACT:

The methods used in Alberta for gathering, testing and treating of produced fluids in the 8 to 18 API range varies widely. The methods found to be most suitable depend largely on the physical properties of the particular produced fluids and the method of enhanced recovery utilized in their production.

The particular physical properties that dictate the method of transport and treating are: oil gravity, water gravity, sand content, clay content, oil viscosity, emulsion viscosity, aromatic content and asphatlene content. The methods used for enhanced recovery also play an important role in determining the processing requirements. Some of the more common methods are:steam cyclic injection, steam drive, air fireflood, oxygen fireflood and steam/CO_2 flooding. Climate also plays a part in determining the processing requirements.

This paper explores the full range of gathering and processing methods utilized in Alberta and presents the features that led to a particular selection. Numerous examples from Colt's work experience on approximately 50 pilot and commercial facilities are presented outlining the problems experienced by the various operators and how the process and facility design was chosen to minimize specific operational problems, captial and operating costs.

1 INTRODUCTION

The material presented here deals specifically with production of oils in the 8 to 20 API range. These oils are found in the heavy oil belt which runs from Southern Saskatchewan to the tar sand deposits in Northern Alberta. Production has increased steadily over the past 10 years as the heavy oils and tar sands begin to play an ever increasing role in Canada's oil supply.

Initial attempts at producing this oil consisted of small scale pilot facilities. These pilot facilities concentrated manily on obtaining good reservoir production data and on proving downhole completion techniques. Little attention was given to the surface production facilities. However, as production, and hence the size of the surface facilities increased, operators began to find that available processing technology was not satisfactory for the Canadian fields.

Development work and testing was undertaken by production companies and engineering companies to derive better methods for handling and processing heavy oils. This work was required since most of the available heavy oil technology came from California where warmer climate, and different oil and reservoir properties made handling of heavy oil much simpler. The key difference in the Canadian oilfields were:

1) Cold climate
2) Sand and clay production
3) Highly asphaltic oils

These three factors necessitated the development of new techniques for handling Canadian production.

The production systems described here represent the technology developed over about 10 years. The systems have been in operation for several years and are well proven. The design data and methods are available which allow adaptation of these systems to other oilfields which will have their own unique operating problems.

2 FLUID GATHERING SYSTEMS

2.1 General

A number of methods are used for gathering the production fluids for processing and subsequent transportation to market. The methods utilized fall into 3 categories:

1) Truck transport
2) Direct pipelining
3) Pipelining from remote satellite facilities

2.2 Truck Transport

Truck transportation of fluids has been used for many years and was the first system utilized for transporting the produced fluids. At the present time, this method is still used extensively in areas where wells are widely spaced. Most of the areas using truck transportation are on primary production or cyclic stimulation using portable steam generators.

Trucking the fluids is fairly expensive, however, it can be done effectively when the reservoir conditions dictate it's use. Figure 1 shows a typical truck terminal flowsheet.

Each production well is equipped with one or possibly two heated storage tanks. Gases produced with the fluid or out of the wellbore annulus are routed to a wellsite flare stack and burned off. The produced liquids are accumulated in the wellsite tanks and are periodically picked up by a truck.

The tanks have been simplified and standardized to a high degree to allow mass production. Each tank is equipped with a gas fired burner, thermostat control and internal firetube. Natural gas or propane is generally used as fuel. The burner comes on automatically to maintain the tank fluid at about 65°C.

Truck loading is done by gravity. To achieve this, each tank is equipped with a drop down loading spout. The truck driver simply pulls the loading spout down which allows the tank fluids to flow by gravity into the hatch opening on the truck.

Each tank is also equipped with a removable cleanout door and a bottom pump out connection. These allow complete draining and cleaning which is required periodically.

The trucks utilized can carry about 16 M^3 of fluid. The trucks are generally insulated to prevent the fluids from cooling during transport. Most of the trucks are equipped with a pump for loading or unloading. This pump is run from a mechanical drive take-off from the engine.

Pump loading and unloading of the trucks, however, is too slow and is seldom done. For fast unloading, the trucks are equipped with a bottom dump valve which allows fast gravity unloading in about 5 to8 minutes for a 16 M^3 truck load. This bottom unloading method also helps to minimize solids accumulation in the trucks.

The wellsite tanks eventually fill up with sand and clay that must be cleaned out. This cleaning is most effectively done using high pressure water lances and a vacuum suction system to remove the solids slurry. Specifically designed vacuum trucks have been developed for doing this tank clean-out.

The solids are usually taken to a central truck terminal for cleaning, separation and disposal.

2.3 Flowline Transport

Pipeline transport of fluids directly from the producing wells to a central plant or satellite collection facility has been done successfully at a number of locations. This method of transportation has begun to take over in the more highly developed oil fields.

The benefits of being able to gather produced fluids by pipeline for initial processing are many. However, with heavy oil there are severe limitation on where pipelines can be used. The limitation are dictated by the properties of the produced fluids.

The key fluid properties which determine whether pipelining is practical are as follows:

1) Sand volume produce and particle size

2) Emulsion viscosity

3) Water content of the fluid

4) Annulus gas volume

Generally, maximum flowing pressure at the wellhead must be kept below 1000 kPa. At higher pressures, well pump performances is severely affected causing excessive pump wear and loss of pumping capacity. The overall flow line pressure loss, therefore, must be kept low. To do this, pipeline velocity is kept low, usually in laminar flow. In addition, the flow lines are generally insulated to prevent temperature loss and the associated higher viscosity and pressure drops. As a general rule, pipeline distance direct from a well must be kept to less than 500 meters.

Viscosity, and of course, pressure drop is highly dependent upon the produced fluid water content. Fluid viscosity generally drops rapidly above 50 vol. % water allowing easier transport by pipeline.

High production of solids from the wells can make pipeline transport difficult or even impractical. The fluid velocities used in the pipeline are usually low enough to have laminar flow. Therefore, sand and solids will tend to settle out in the pipeline.

If the solids volumes are small, pipeline plugging can be prevented by regular insertion of a cleaning device (pig) into the pipeline to push the solids out of the line. However, if the solids reach a signficiant volume, the frequency of cleaning required will make pipelining impractical unless solids are separated out at the well site.

Generally the annulus of a heavy oil well must be vented and kept at fairly low pressure for effective pumping. The maximum desired back pressure at the well annulus is about 100 kPa. This low pressure generally makes it impractical to recombine the annulus gas into the produced fluid.

Annulus gas is either vented and burned off at each well or is pipelined to a central plant by separate, low pressure pipeline. Again, pipeline pressure drop places fairly severe limits on the practical distances that can be tolerated. Also, the annulus gas is generally water saturated which allows large volumes of water to condense in a pipeline as the gas cools off. Generally, the annulus gas flow line must have automatic drain pots at low spots to prevent water build up and the associated high pressure drops.

The annulus gas generally has a high enough heating value to make it usable for heater or boiler fuel. This may make it attractive to put in a pipeline collection system to save the annulus gas for fuel.

Lines in the Canadian oil fields are generally buried below frost depth (about 3 meters) to prevent freezing during a winter shutdown.

2.4 Satellite Flowline System

To extend the practical distances available for pipelining of produced fluids, local satellite collection facilities can be utilized. A number of these types of systems are in service. The largest is operated by Alberta Energy Company at South Jenner, Alberta. The satellite flow schematic is shown in Figure 2 of the Appendix.

Fluids from the wells are pipelined to the satellite facility. Here, they may flow into surge tanks, however, in some cases it is more desirable to flow directly into a pressurized surge vapor trap vessel. Generally fluids are partially or totally degassed at the satellite.

Most of the field systems do not utilize any diluent to aid in pipelining of the produced fluids. The flow distances are generally short and the use of high head pumps is sufficient for pipelining. Special high head viscous fluid pumps are utilized to boost the fluid pressure sufficiently to get it to the main central treating plant.

Figure 3 shows a typical gathering system flow scheme.

3 FLUID MEASUREMENT AND ANALYSIS

3.1 General

Separation measuring and analysis of produced fluids is an important part of any production system. The ability to measure accurately the volumes of gas, oil, water and solids produced by the wells is important.This flow data allows proper analysis of the reservoir well pumps and enhanced recovery methods.

3.2 Separation

Separation of the produced gas, oil and water for measurement can be quite difficult in heavy oil production. Separation of the oil and water in particular is not practical because of the difficulty encountered in achieving reasonable pure separation of the two liquid phases.

Most operators have given up trying to separate the oil and water for metering. They do accurate metering of total fluid flow and then rely on some means of analysis to establish the relative oil and water volumes. In these installations a simple verticle vessel for gas and liquid separation is effective. Liquids are dumped from the very bottom of the vessel to eliminate any solids accumulation. In systems anticipating high solids production a cone bottom is used on the separation vessel.

Some operators still utilize horizontal, long residence time separators for metering. However, the oil/water separation is not complete enough to eliminate the need for a means of accurate analysis of the residual water in the oil phase. These separators also have problems with solids deposition due to the long residence time.

3.3 Gas Measuement

Accurate gas measurement can be difficult in heavy oil facilities due to highly variable flow volume, plugging due to oil carry over and low operating pressure.

Generally the meters operate at low pressures (below 700 kPa) where pressure compensation is a necessity for all types of gas meters.

Conventional orifice meters, with chart recorders have proven to be quite effective for measurement of test separator and treater off gases as long as the flows are reasonably steady. Also the flow volume must be large enough to give a reasonable orifice size. If the orifice is too small it will plug off too readily.

For small gas flows where the flow is highly variable, rotary positive displacement (Roots) meters have proven to be most effective. The meters can be readily cleaned and do not plug easily.

For some of the very low pressure gas streams such as annulus vent gas going to flare or tank vent vapours, insertion turbine metes have proven to be most effective. These meters have the added advantage that the moving parts may be extracted from the gas stream for repair or cleaning.

3.4 Total Fluid Measurement

Total liquid flow measurement can be accurately done in a number of ways. At the truck in facilities, generally total fluid receipts are done by using a truck weight scale. Each truck is accurately weighted in and out of the facility to determine the net fluid delivered. The fully electronic, multiple load cell, pitless scales have become the most popular type. They have proven highly reliable with very few maintenance or repair problems.

For flowing systems, we have successfully used two types of liquid flow measurement. These are:

1) Turbine flow meters

2) Vortex Shedding flow meters

Vortex shedding meters are relatively new but they seem to stand up well and remain in calibration longer than the turbine meters. Both meters, however, will drift off calibration frequently as they experience wear due to solids erosion. Regular means of meter calibration is essential.

A more reliable means of measuring fluids flow is to use a dump separator system. This consists of a vertical separator with a high and low liquid level float switch. The separator liquid dump valve opens each time the high level switch is reached and closes when the low level switch is reached. The liquid volumes held between the level switches can be accurately calculated.

The level switch signals are routed to a programmable controller which counts the number of fills per day and from this information calculates the daily flow volume. This flow measuring system has been quite reliable and trouble free.

The simplest and most reliable method of checking meter calibration is to run the meter outlet fluid into a small tank for several hours and measure the tank level increase. The volume increase in the tank over a given time is then accurately determined. Permanent calibration tanks have been installed at a number of facilities to facilitate frequent meter and water analyzer calibration.

3.5 Water Analyzers

These analyzers are commonly referred to as BS & W (Basic sediments and water) analyzer. This terminology is not correct as none of the device available can measure solids.

The water analyzers are an important part of the fluid metering system in that they allow total fluid production to be split into oil and water quantities. All of the devices must be calibrated regularly by doing standard laboratory solvent dilution and centrifugal oil/water separation tests.

Several types of devices have been developed for measurement of the water content of oil. There are two main types of devices:

1) Radio frequency

2) Electrical conductivity

All of these devices can be used successfully to determine water contents in the 0.5 to 10.0 vol. % range. Only the radio frequency devices have proven reliable in measuring water contents in excess of 10% or below 0.5 vol. %. Even these probes require frequent calibration checks.

Calibration tests on the water analyzers are usually done simultaneously with testing of the liquid flow meter. Fluids are run down into a test tank. Once the tank is full, liquid samples are taken at about 0.3 meter intervals over the fluid level in the tank. These samples are centrifuged in the laboratory and an average water content of the fluid is computed. This is compared to the flow average readings of the analyzer over the test duration. Calbirations done in this manner have proven to be very accurate.

4 BULK FLUID SEPARATION

4.1 General

Bulk fluid separation is generally undertaken as the first step in processing produced fluids at any central treating plant. The primary purpose of this initial separation is to remove most of the gases and most of the solids from the produced fluid along with the majority of the water. Several types of equipment are available for undertaking these separations.

4.2 Degassing

It is highly important to achieve proper gas removal from the bulk fluids prior to attempting oil/water/solids separation. The gas bubbles tend to prevent proper gravity separation in the liquid phase. Vortexing separators have been found to be very effective for gas/liquid separation while they provide low liquid phase hold up. Low liquid phase hold-up is desirable to minimize solid precipitation and plugging in the degassing separator.

The vortex separation device is often times built into the separator vessel or tank. However, if a large tank or vessel with large surface area is being used for oil/water/solids separation, the vortex degassing device may not be necessary.

4.3 Tank Separation

Atmospheric tanks have proven to be one of the most effective and inexpensive devices available for solids removal and bulk water removal. The tank can also be equipped with internal heating devices to allow heating of the fluid to improve fluid separation.

Because fluid movement must be limited to very low velocities to allow proper gravity separation, design of the tank flow path is very important.

Poor internal design results in poor fluid flow patterns, low fluid effective residence times and poor separation.

If heating is also being done in the tank, the heating zone should be physically isolated from the settling zone. Figure 4 shows a typical tank treater where the heating zone has been isolated and the fluid flow pattern has been optimized.

The oil flow is forced to spiral upward and around which provides the best possible flow pattern for oil water separation.

The bottom of the tank has acone bottom along with rings equipped with water spray jets. This arrangement allows frequent removal of separated solids without taking the tank out of service. The water jets stir up the solids and move them to the bottom of the cone. The solids slurry is then drained out via the dump line off the bottom of the cone.

One other feature of the tank treater design is worth noting. Two purge nozzles are located close to the oil/water interface.

Solid, in particular clays, waxes, and iron sulphide tend to accumulate at the interface. These solids are drawn off periodically to prevent excessive build up. These solids can not get out of the tank unless they are drawn off at the interface.

4.4 Pressure Separators

In certain situations, it becomes desirable to use pressure vessels for primary oil/water/solid separation. Separation under pressure is desirable when;

a) the produced fluid arrives at the treating plant at temperatures above about 95°C.

b) when the produced oil is very viscous and requires temperatures above 95°C for proper oil and water separation.

In both of the above situations it is necessary to use a pressure vessel for separation since the water in the fluid would otherwise flash to steam. If this happens separation ceases and the fluid foams badly.

A typical heated pressure separation vessel is shown in Figure 5. In conventional oil fields this device is the well recognized heater - treater. However, for heavy oil service the treater must be substantially modified in order to operate effectively.

The following modifications are made for heavy oil service:

1. Residence times are increased, substantially to several hours.

2. Fluids entering the separation section are forced to enter near the oil/water interface or, where some solids washing is desired, the entering fluid may be forced to enter below the oil/water interface.

3. Oil/water interface level control must be done with special detectors as the gravity difference is generally too small for float type controllers to work properly.

4. Heat coils are provided in the separation zone water phase. These make up heat to the water in the treater so that it won't cool off. If the water phase cools off too much, the fluid near the interface becomes very viscous and does not allow water droplets to settle through to the water phase.

5. At least two oil/water interface draw off points are provided to allow purging of solids that build up at the interface.

6. A complete solids removal system is installed with desand water spray jets and slurry dump valves.

Desand water jets are also installed to prevent solids build up on the firetube. This causes hot spots and firetube failures.

The treaters are more expensive devices and are more difficult to operate than tanks. However, for the situations stated, they are required and can be made to work efficiently if the modifications outlined are made.

Some of the treaters used in light oil utilize internal electric grids or coalescing media to improve operation. However, neither of these items are recommended for heavy oil service.

The media rapidly plugs with clay, sand and asphaltines. The electric grids generally short out and have not proven to be effective for heavy oils.

4.5 Chemical Treatment

The use of proper chemical addition is very important for proper operation of all gravity separation equipment. This is true for oil/water separators and treating or water skim separators for final oil removal from produced water.

Chemicals are injected for 3 purposes:

1) Emulsion breaking
2) Corrosion control
3) Coagulation of clay fines

The proper chemicals are injected upstream of the separation equipment. Preferrably, the chemicals should be injected sufficiently upstream of the separation equipment to give the chemicals reasonable reaction time. It is very important to ensure complete mixing of the chemical at the point of injection.

Mixing can be done very effectively with in-line, static mixer devices. There has been some resistance from operators to install the mixers. The concern is that the mixers will create emulsions. However, the creation of emulsions using the mixers does not in fact become a problem and they do work very effectively in getting the chemicals to work efficiently.

In trucked in facilities, where the incoming fluid has been exposed to air, problems have been observed with oxygen corrosion. Injection of oxygen scavenger chemical has proven very effective in eliminating this problem.

There are many chemicals available that aid in breakdown of emulsions, however, the particular type to be used in a specific application can only be determined by field testing. Simple bottle tests can be used to determine which chemical gives the shortest breaktime of the particular emulsion sample. No one chemical has been found that is effective in all heavy oil applications.

Polmer type water treating chemicals have been tried in recent years and have proven to be very effective in removal of clay fines from the produced fluids. Control of the clay build up improves all types of gravity separation equipment and also decreases the need for purging of high solids slop oil from the separator oil/water interface areas. These chemicals have also proven very effective in improving water clean up separator performance.

In summary, proper injection and dosage of chemicals is an essential part of any heavy oil cleaning plant operations.

5 SOLIDS HANDLING AND DISPOSAL

5.1 General

The separation, cleaning, handling and disposal of sand and clay fines is becoming a very significant problem for all of our heavy oil producers. Extensive research and testing has been done to improve well completions in order to minimize the production of solids from the wells. This has definitely reduced the amount of solids produced, however a significant volume of solids are produced daily at each of the facilities involved in oil cleaning.

5.2 Equipment Cleaning

Equipment cleaning generally must be done frequently, therefore, most treaters, free water knockouts, and separation tanks are equipped with permanent on-line desanding systems. The desanding is accomplished with high velocity water jets which slurry and transport the solids to one of the slurry blowdown lines. Figure 4 shows a typical system for on-line tank desanding. Figure 6 shows a typical arrangement for treater or pressure vessel desanding.

The solids slurry is generally transported to a collection tank for further cleaning prior to final disposal. Pressure vessels generally have sufficient pressure to drive the slurry to the collection tank. Atmospheric tanks, however, must have the slurry sucked out. Liquid eductors have proven very effective for sucking away the solids slurry.

■ 5.3 Tank Cleaning

The individual tanks used to accumulate fluids at each well gradually fill up with solids. Originally, operators used to drain each tank down every few months and send a crew in to manually shovel out the oil sludge. This was very time consuming work.

Special cleaning trucks were developed that now allow on-line cleaning of the tanks. To allow this each tank is equipped with a bottom 4 inch drain valve and a 3 inch water injection valve. The 3 inch valve has a packing gland attached to it that allows entry of the high pressure water cleaning lance. The high pressure water lance is moved around the tank bottom while fluids are sucked back into the cleaning truck by vacuum. This method is now finding wide acceptance for cleaning lease tanks and the bottom of storage tanks at the cleaning plant that are not equipped with internal desand systems.

■ 5.4 Ecology Pit

Ecology pits have been the standard means of collecting and storing solids prior to disposal. These are large concrete pits used to dump oily solids collected from lease tanks, plant equipment of oil spills. These pits, however, are falling into disfavour for the following reasons:

1. Concrete cracking allowing leakage of oily brine into the local groundwater.
2. Deaths of many birds or small animals that fall into the pit and can not get out.
3. Cost of construction, monitoring and maintaining these large pits.

Oily water is regularly skimmed off the pit and sent back to the cleaning plant for clean-up. The solids that eventually fill the pit completely have historically been dug out with a back hoe and hauled by truck to locations where the solids are dumped and spread on local roads.

The use of produced solids on local roads is becoming a problem because of the voulme of material and environmental concerns. The solids contain large amounts of oil and salts which wash off into the drainage system and end up contaminating local lakes and streams.

Groups of producers are now looking at proper means of sand clean-up for land fill. The volumes now being produced can no longer be absorbed by the local road system.

■ 5.5 Solids Cleaning

Cleaning of sand and clay collected from produced solids requires several basic steps to produce a solid that is acceptable for simple land fill disposal.

The simplest part of the cleaning is removal of oil from the solids. This can be simply achieved by hot water washing in a liquid cyclone and cleaning tank. Figure 7 shows a sand cleaning tank that has been used to achieve oil free soids. The tank cleaning system, however, eventually must be drained or mechanically cleaned as clay sludge builds up in the system.

A small slip stream can be purged from the tank and sent to a clarifier tank where flocutating material is added to cause the clay material to settle out. The clay sludge is small in volume and can be blowdown to a collection pit.

Clean sand produced from the tank cleaning system is not acceptable for disposal on roads since it no longer has any oil binder with it. The clean material could be put to simple land fill however, the extremely high salt content of the sand makes it undersirable for pit disposal in the farming areas where most of the heavy oil is produced.

If fresh water is available, a dilution wash step with fresh water in a counter current system can be used to remove the salt with a minimum amount of fresh water. Once the salt content of the solid is reduced it is perfectly acceptable for land fill disposal.

6 PRODUCED WATER SYSTEM

■ 6.1 General

Collection, clean up and disposal of produced water represents a major portion of the facilities required for heavy oil field processing. The type of processing required depends upon the ultimate end use of the water.

For water going direct to disposal injection wells, the degree of clean-up required depends upon the reservoirs plugging tendency. However, if the water is to be re-used to make steam in the injection boilers an extensive treatment system is always required.

■ 6.2 Collection and Primary Separation

Produced water is collected mainly from the primary separators and the treaters. The flow rates can be highly variable, particularly at cyclic steam injection fields. This variable flow rate makes it essential to have a reasonable surge voume available in the system.

In systems where only simple oil skimming is employed, the surge volume is best lcoated downstream of the water skimming device. In other systems where secondary processing such as induced gas floatation (IGF) is used, the surge volume must be placed upstream of the secondary treatment equipment as IGF equipment is sensitive to flow changes.

Primary separation is most effectively done in specially designed water skim tanks. Figure 8 shows the internals required for maximum skim efficiency. In addition to the special internals, a small volume of fuel gas is injected into the water inlet line. This injected gas has proven to aid in oil separation and improves the overall tank peformance.

The skim tank is also equipped with a cone bottom plus a system of desanding water jets for slurrying solids to the tank bottom.

Chemicals also form an important part of the primary water treatment. Generally, chemical treatment will consist of corrosion inhibitor, clay floculating polymers and possibly an oxygen scavenger. It is important to inject the chemicals well upstream of the separator equipment. Good mixing is also essential and can be achieved with a static mixer device.

A properly designed primarly separation tank will typically reduce the oil content of the water to less than 200 ppm.

■ 6.3 Secondary Treatment

Secondary separation devices can effectively remove the oil content to less than 20 ppm. The device currently used extensively for this secondary treatment is the induced gas flotation unit, commonly known as an IGF unit.

These units run at pressure very close to atmosphere. They generally consist of 3 or 4 contact cells, which operate in series. Figure 9 shows the basic operation of a mechanical type of IGF unit. Figure 10 shows the basic operation of a hydraulic type of IGF unit.

Both types of IGF units have been used successfully in heavy oil plants. Each type has advantages and disadvantages and selection generally depends upon the intended application. Generally, as the water flow volume gets larger, the mechanical units become more cost effective. However, for smaller flow volumes, the hydraulic units have proven more attractive.

The principal of operation is simple. Gas bubbles are introduced into the water and these bubbles attach to oil particles in solution providing improved bouyancy. The oil/water froth floats to the surface and overflows by gravity into a froth collection tank. The oil/water froth is pumped back to the primary water skim tank feed for re-processing. Generally this froth will be 90 to 95% water.

In the mechanical units, the mechanical mixer device in each cell induces gas bubbles down into the water. In the hydraulic units a recycle water pump is used to pump though a venturi device which allows gas into the recycled water phase.

It is important to keep a slight positive gas pressure on the unit and also to purge the unit with gas continuously. A good purge is essential to keep hydrogen sulphide and carbon dixoide vapour from building to high concentrations in the unit.

■ 6.4 Final Polishing and Treatment

Generally final polishing and treatment of produced water is only done where the water is intended for reuse in the boilers. For this application, oil removal to less than 1 ppm is required. In addition, total hardness must be reduced to less than 1 mg/l and dissolved silicia must be removed to less than 20 ppm.

In order to achieve the final water quality required, several process steps are used. These are in sequence:

1. Hydromation Filters
2. Hot Lime Softener
3. Weak Acid Sodium Cycle Resin Polisher with Acid/Caustic Regeneration

The Hydromation filter has proven to be effective in reducing oil and solids content to less than 1 ppm. The units have also operated continuously for many months with no down time or media changes required.

The media consist of ground walnut shells. These shells are water wet and therefore oil can be easily regenerated off them. Regeneration is done by slurrying the media out of the vessel through a wedge wire mesh filter which allows oil and water to pass through but not the media particles. A high volume regeneration pump fluidizes the media out through the wire mesh filter. See Figure 11.

The hot lime softener system is a device used commonly in municipal or industrial water treating applications. Lime is mechanically mixed into the feed water. The lime forms a suspended sludge blanket in the cone bottomed clarifier section of the softener. The lime sludge traps out the calcium and magensium hardness along with most of the dissolved slicia. The lime sludge is generally blowdown to a collection pond which eventually fills with sludge. The pond can be drained and then land filled. Water from the sludge pond is drawn off periodically and recycled to the treatment system.

After lime softening, sand-bed gravity filters are used, primarily to catch any residual lime carry over from the softener.

Final polishing is still required in order to get below 1 mg/l total hardness. This is accomplished using a weak acid sodium cycle ion exchange bed. The ion exchange resin is periodically regenerated with acid followed by caustic to reactivate the resin.

Standard strong acid ion exchange resins using salt regenerators are not acceptable for produced water softening as the TDS level generally exceeds 10,000 mg/l. Most of the TDS is sodium chloride. The high level of sodium percent in the water causes constant regeneration of the resin which releases hardness ions from the bed.

A typical overall flow schematic for produced water treatment for re-use is shown in Figure 12.

7 OIL POLISHING AND SLOP TREATMENT

The conventional type of heated gravity separation equipment whether it is atmospheric or pressure treating equipment has limited capabilities in heavy oil service. BS & W contents below about 1 vol. % are difficult to achieve on a consistent basis. This results in a requirement for large off specification storage an re-run systems. The large re-run capability can restrict plant throughput and is very wasteful in energy and chemical consumption.

Slop oils which are typically high in solids content are very difficult to clean up using gravity separators, even in the presence of diluent and chemicals. These oils typically come from treater tank interface blowdown, pressure treater interface blowdown, water tank skim oil, ecology pit skim oil and tank bottoms sludge.

Attempts have been made to clean up the slop oils using batch heated tanks where several days of retention time is available. Light hydrocarbon diluent addition along with high chemical dosage is used to achieve the best possible results. The product fluid is generally no lower than 10% BS & W and therefore must be recycled through the main oil treating equipment. This usually results in upset of the main treating equipment unless the amount of slop oil recycled is kept very low, usually only 2 to 3% of the total plant feed.

These treating problems were investigated several years ago by Colt Engineering at a number of heavy oil facilities. The investigations pointed out the need for a new totally different oil treater that could clean up slop oil and would also serve as a final clean up unit for total oil treating situations.

A 160 M^3D experiemental unit was constructed and put into service for testing at a heavy oil pilot facility in 1983. Operation of the small test unit was so successful that the plant operating company purchased the test unit and has kept it in continuous service since it was installed.

Operation of the unit proved to be extremely trouble free. It requires almost no operator attention except during a start-up.

The Colt Treater operates on a distillation principal for removal of water and therefore is not dependent upon viscosity, specify gravity or chemical addition to work properly. The unit does not remove slids from the oil, these pass right through the unit. Once the emulsion and water phases have been destroyed any residual solids readily drop out of solution and can be removed by settling in downstream tankage.

Figure 13 shows the typical flow scheme for the Colt Treater. The units generally produce a by-product light gravity (60-55 API) distillate which is condensed and collected along with the evaporated water.

The distillate has been used in many different ways to improve plant operation. Some operators recycle the distillate to the inlet of their pressure treaters to reduce viscosity and specific gravity. In other fields, the distillate is blended with clean oil for use as a flushing fluid when servicing the wells.

One operator actually accumulates the distillate and sells it to the pipeline company for blending diluent.

A total of 18 units have been installed in the last four years in Alberta. Fluids with water content as high as 50% have been treated along with fluids having as high as 30% solids. Difficult pit skim fluids and tank bottoms have been treated without difficulty.

8 ENHANCED RECOVERY SYSTEMS

Several techniques are used for improving heavy oil production from the reservoir. In particular we have designed the surface facilities required for the following types:

1. Cyclic steam injection
2. Steam drive
3. Air fire flood
4. Oxygen fire flood
5. Carbon dioxide/water flood

Most of the fields utilize a cyclic steam injection system. This appears to be the best method for most of the reservoirs in Alberta.

For steam generation, a number of manufacturers supply high flux compact boilers for production of 80% quality steam at up to 17000 psig pressure. Because of the high water content of the produced steam water quality is not critical and very high heat fluxes can be used for design of the boiler tubes.

Many operators are using compact trailer mounted units complete with electric generators, water treating unit and controls. Units up to 25 MMBTU/hr. can be made quite portable. These units are moved about every 3 weeks to a new well.

Another popular method is to directionally, or slant drill a number of wells from one small drill pad. A permanent steam generator is then located on the producton pad to service the wells. One steam generator may provide steam for several nearby drill pads. The steam is distributed by above ground or buried pipeline.

Water treatment for the boilers, when using lake, river or well water generally only requires a salt regenerated ion exchange resin system. This is the most popular type of system.

Air firefloods require large volumes of high pressure (up to 17500 kPa) air. Rotary screw type air compressors are used to boost the atmospheric air up to about 700 kPa. A 3 or 4 stage reciprocating air compressor with interstage cooling is used to compress the air from 700 kPa to injection pressure.

The compression equipment used is fairly standard except that special synthetic lubricants must be used for cyclinder lubrication. The high oxygen partial pressure creates a high explosion risk if any combustible material is allowed to get into the compressed air.

Several compressor explosions have occurred due to contamination of the air. These have been traced to use of improper lubricants or improper inlet air filtration.

The oxygen firefloods are still in the experiemental stage and have been pilot type facilities with only a few wells.Oxygen consumption has not be large enough to justify an air separation plant on site.

The liquid oxygen is brought in by special truck and off loaded into a special insulated high pressure storage tank. The liquid oxygen is pumped to injection pressure and then is put through a heater to vaporize the liquid. All pure oxygen piping must be stainless steel and extreme care must be taken to ensure that no combustible material ever gets into the oxygen piping.

Carbon dixoide floods are also a recent development. This scheme uses alternating injection of CO_2 and then water into the injection wells. The system generally uses a drive configuration with several producing wells clustered around an injection well.

The CO_2 floods are small and liquid CO_2 is trucked to the site and put into insulated pressure storage. Liquid is pumped up to injection pressure and is then heated to vapourize it. CO_2 piping must be kept dry (no water) or severe corrossion problems occur.

Corrosion problems and premature break through have been the major technical problem in terms of surface facilities. At the present time, low oil price and the high cost of CO_2 are holding back major development of CO_2 floods.

Figure 1
Typical Flow Scheme for Truck Terminals

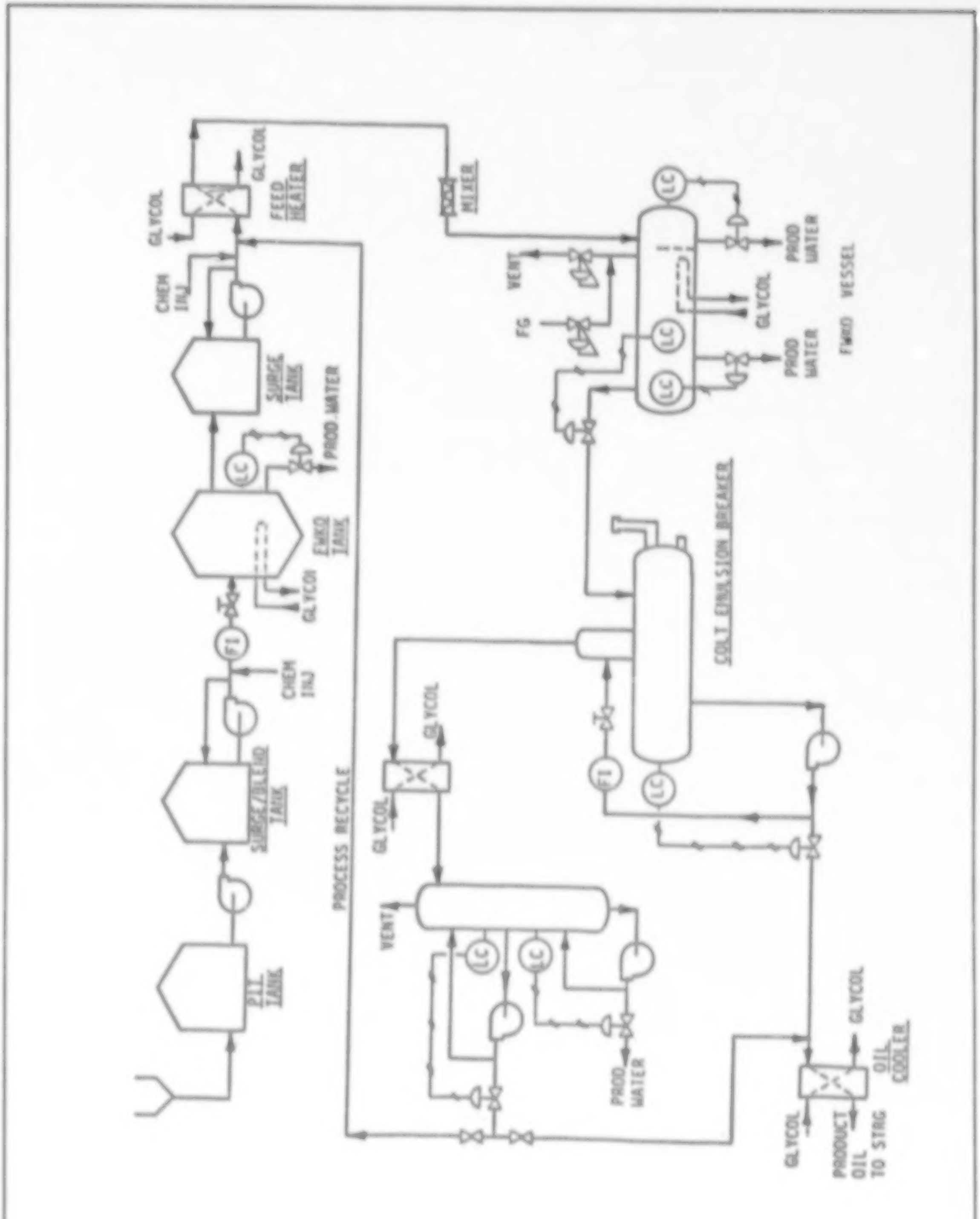

PIT TANK
SURGE/BLEND TANK
CHEM INJ
FI
GLYCOL
FWKO TANK
LC
PROD. WATER
SURGE TANK
CHEM INJ
GLYCOL
GLYCOL
FEED HEATER
MIXER
PROCESS RECYCLE
VENT
FG
LC
LC
LC
PROD WATER
GLYCOL
PROD WATER
FWKO VESSEL
COLT EMULSION BREAKER
FI
LC
GLYCOL
GLYCOL
VENT
LC
LC
PROD WATER
GLYCOL
GLYCOL
OIL COOLER
PRODUCT OIL TO STRG

Figure 2
Typical Satellite Flow Scheme

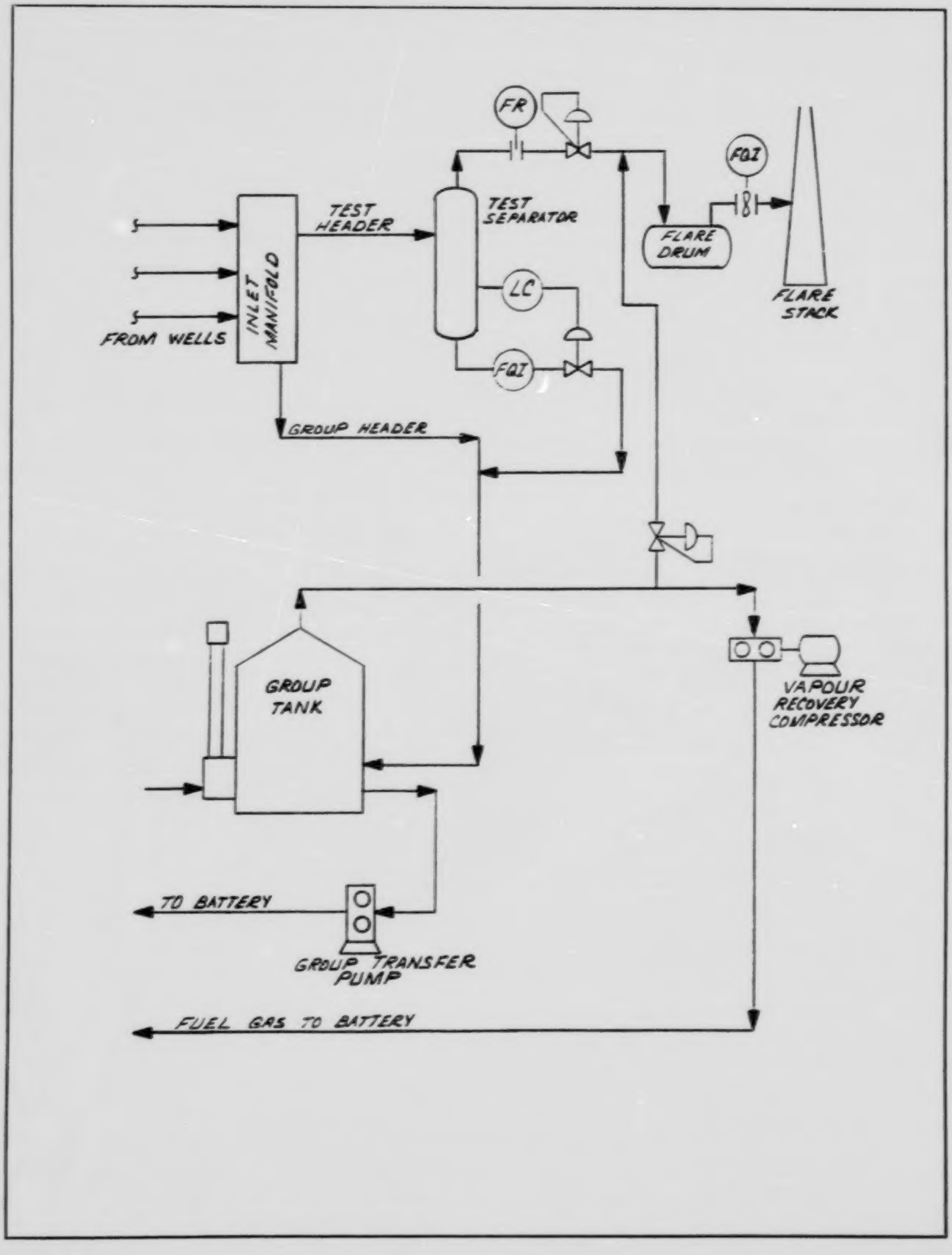

FR
FQI
TEST HEADER
TEST SEPARATOR
FLARE DRUM
FLARE STACK
INLET MANIFOLD
FROM WELLS
LC
FQI
GROUP HEADER
GROUP TANK
VAPOUR RECOVERY COMPRESSOR
TO BATTERY
GROUP TRANSFER PUMP
FUEL GAS TO BATTERY

Figure 3
Number of Wells Connected

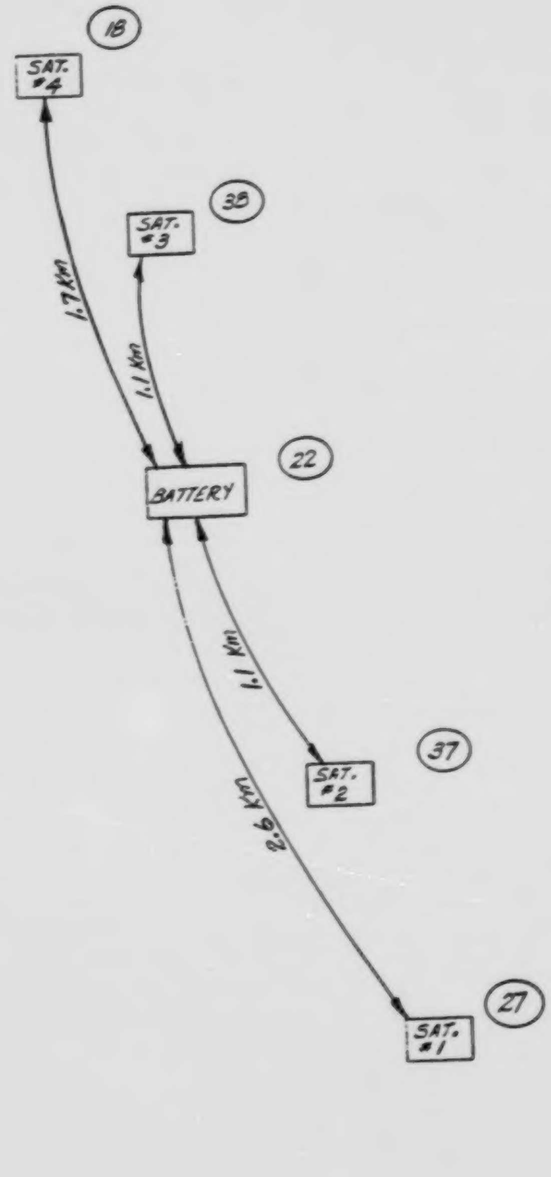

18
SAT. #4
38
SAT. #3
1.7 Km
1.1 Km
22
BATTERY
1.1 Km
37
SAT. #2
2.6 Km
27
SAT. #1

Figure 4
Improved Tank Treater

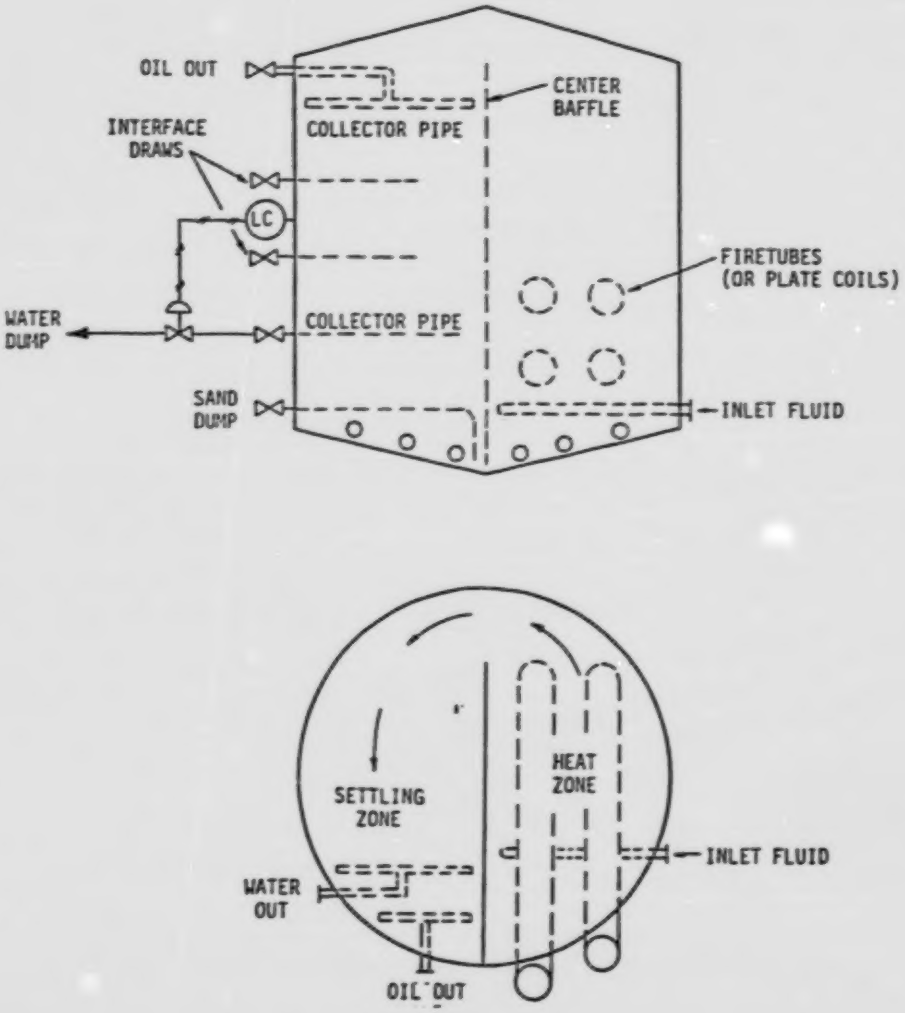

OIL OUT
CENTER BAFFLE
COLLECTOR PIPE
INTERFACE DRAWS
LC
FIRETUBES (OR PLATE COILS)
WATER DUMP
COLLECTOR PIPE
SAND DUMP
INLET FLUID
SETTLING ZONE
HEAT ZONE
INLET FLUID
WATER OUT
OIL OUT

Figure 5
Modified Treater Design For Heavy Oil

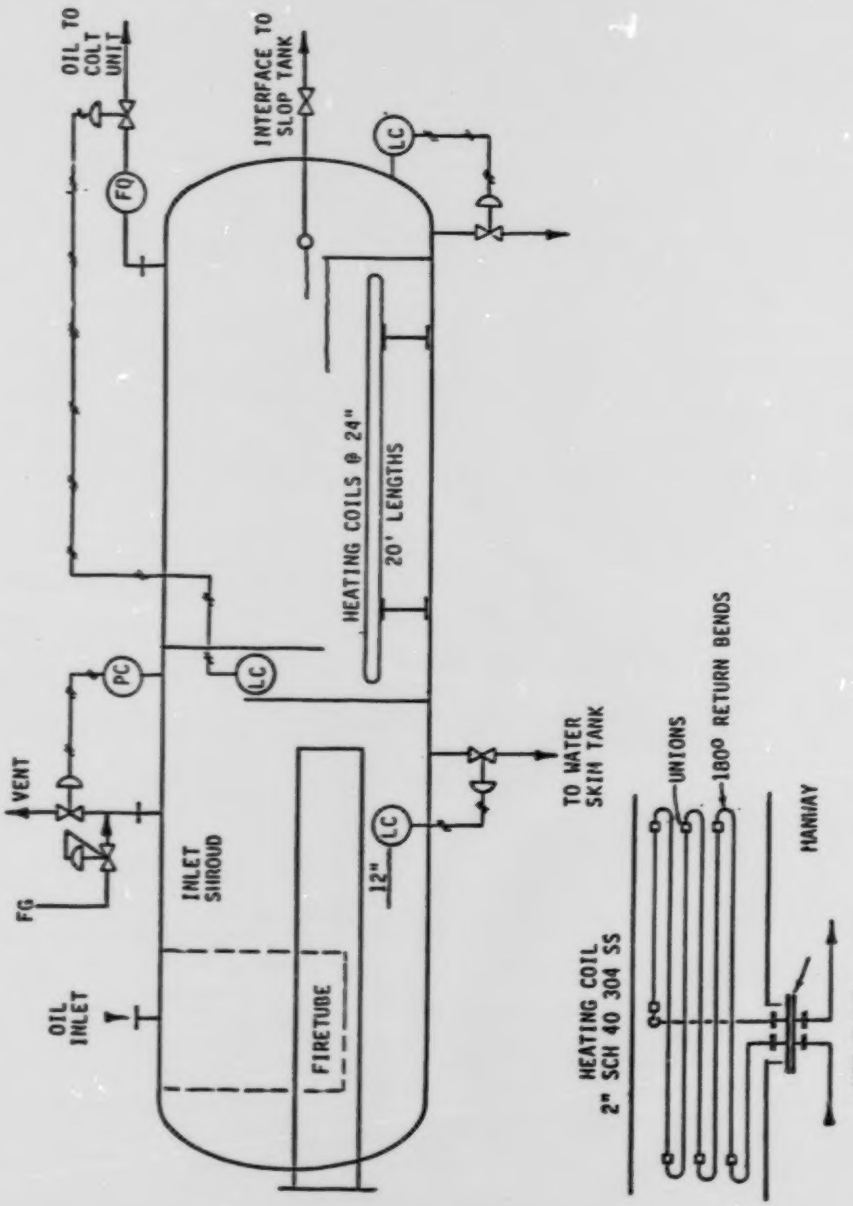

OIL TO COLT UNIT
INTERFACE TO SLOP TANK
FQ
LC
HEATING COILS @ 24"
20' LENGTHS
PC
LC
VENT
FG
OIL INLET
INLET SHROUD
FIRETUBE
12"
LC
TO WATER SKIM TANK
UNIONS
180° RETURN BENDS
MANWAY
HEATING COIL
2" SCH 40 304 SS
HOT FLUID

Figure 6
Treater Desand System

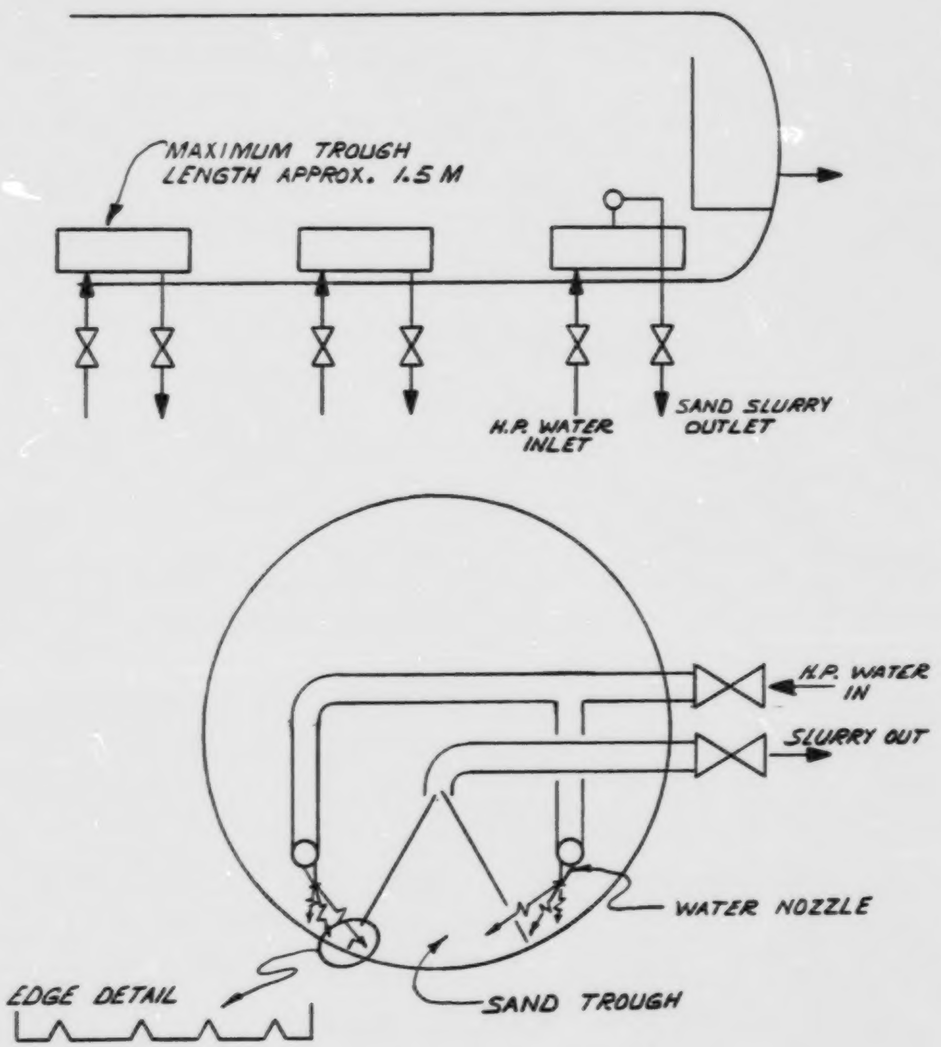

MAXIMUM TROUGH LENGTH APPROX. 1.5 M
H.P. WATER INLET
SAND SLURRY OUTLET
H.P. WATER IN
SLURRY OUT
WATER NOZZLE
EDGE DETAIL
SAND TROUGH

Figure 7
Tank Sand Cleaning System

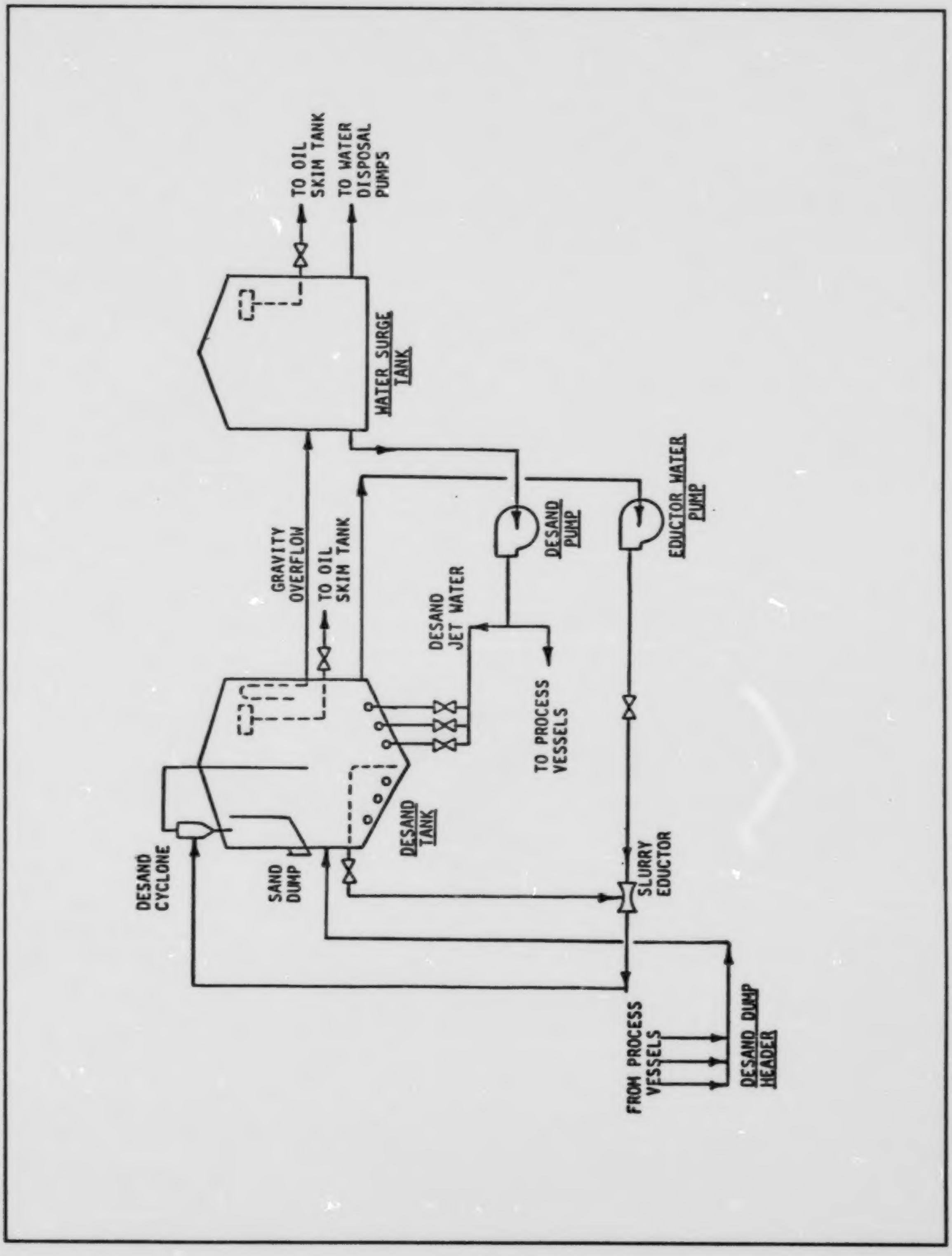

TO OIL SKIM TANK
TO WATER DISPOSAL PUMPS
WATER SURGE TANK
GRAVITY OVERFLOW
TO OIL SKIM TANK
DESAND PUMP
EDUCTOR WATER PUMP
DESAND JET WATER
TO PROCESS VESSELS
DESAND CYCLONE
SAND DUMP
DESAND TANK
SLURRY EDUCTOR
FROM PROCESS VESSELS
DESAND DUMP HEADER

Figure 8
Oil Skim Tank

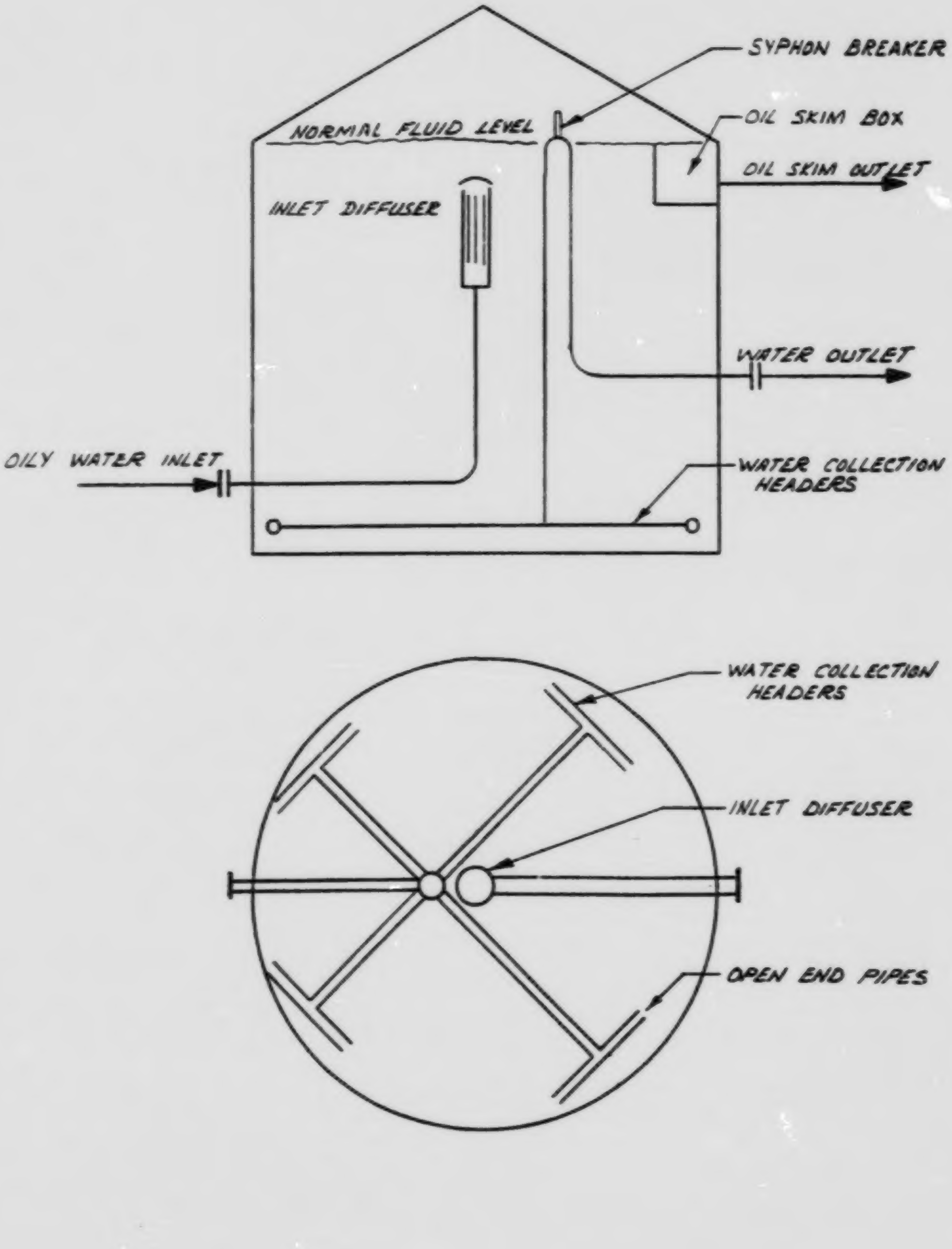

SYPHON BREAKER
NORMAL FLUID LEVEL
OIL SKIM BOX
OIL SKIM OUTLET
INLET DIFFUSER
WATER OUTLET
OILY WATER INLET
WATER COLLECTION HEADERS
WATER COLLECTION HEADERS
INLET DIFFUSER
OPEN END PIPES

Figure 9
Mechanical Gas Flotation Unit

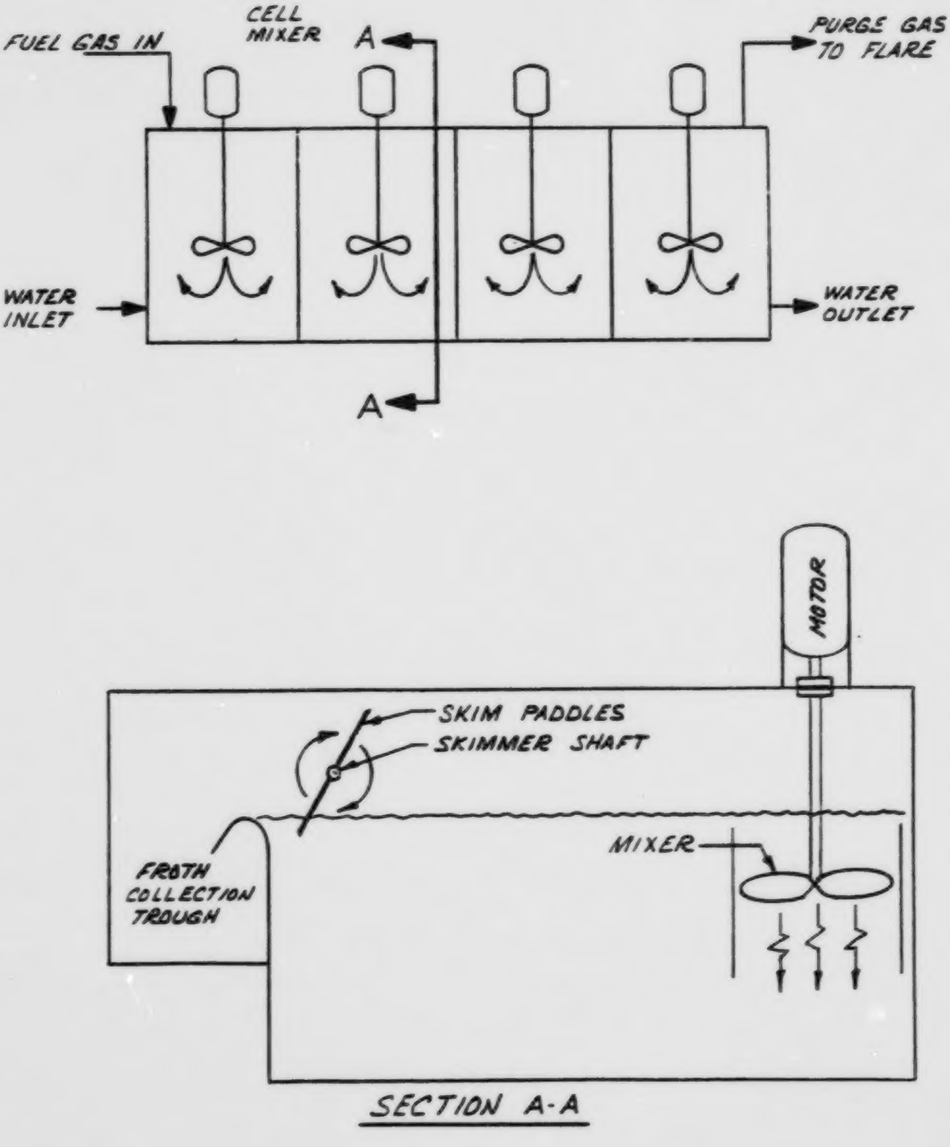

FUEL GAS IN
CELL MIXER
A
PURGE GAS TO FLARE
WATER INLET
WATER OUTLET
A
MOTOR
SKIM PADDLES
SKIMMER SHAFT
MIXER
FROTH COLLECTION TROUGH
SECTION A-A

Figure 10
Hydraulic Gas Flotation Unit

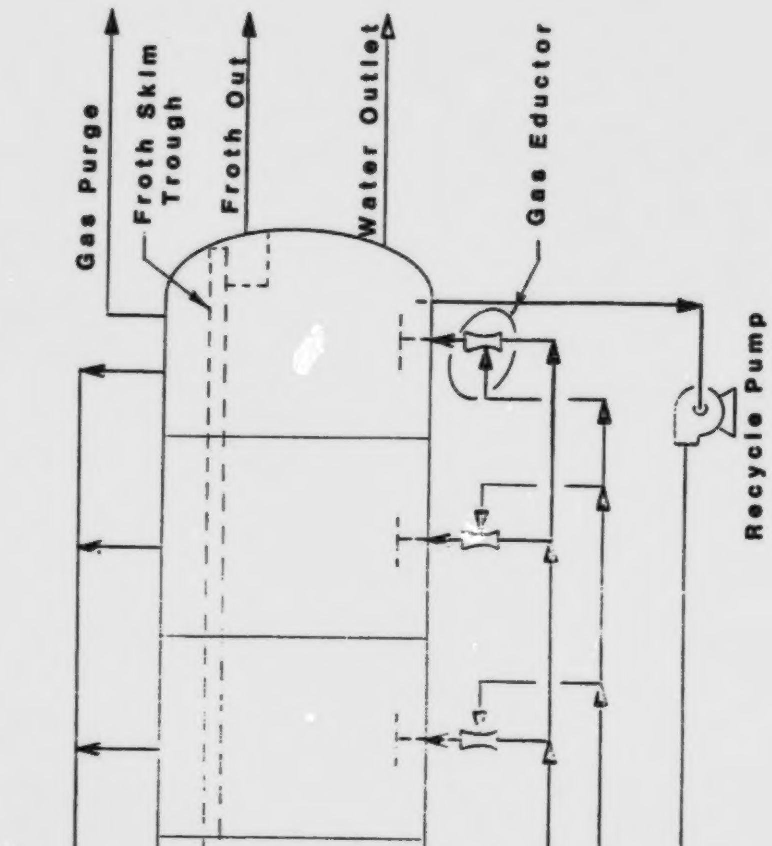

Gas Purge
Froth Skim Trough
Froth Out
Water Outlet
Gas Eductor
Recycle Pump
Gas Supply
Water Inlet

Figure 11
Hydromation Filter

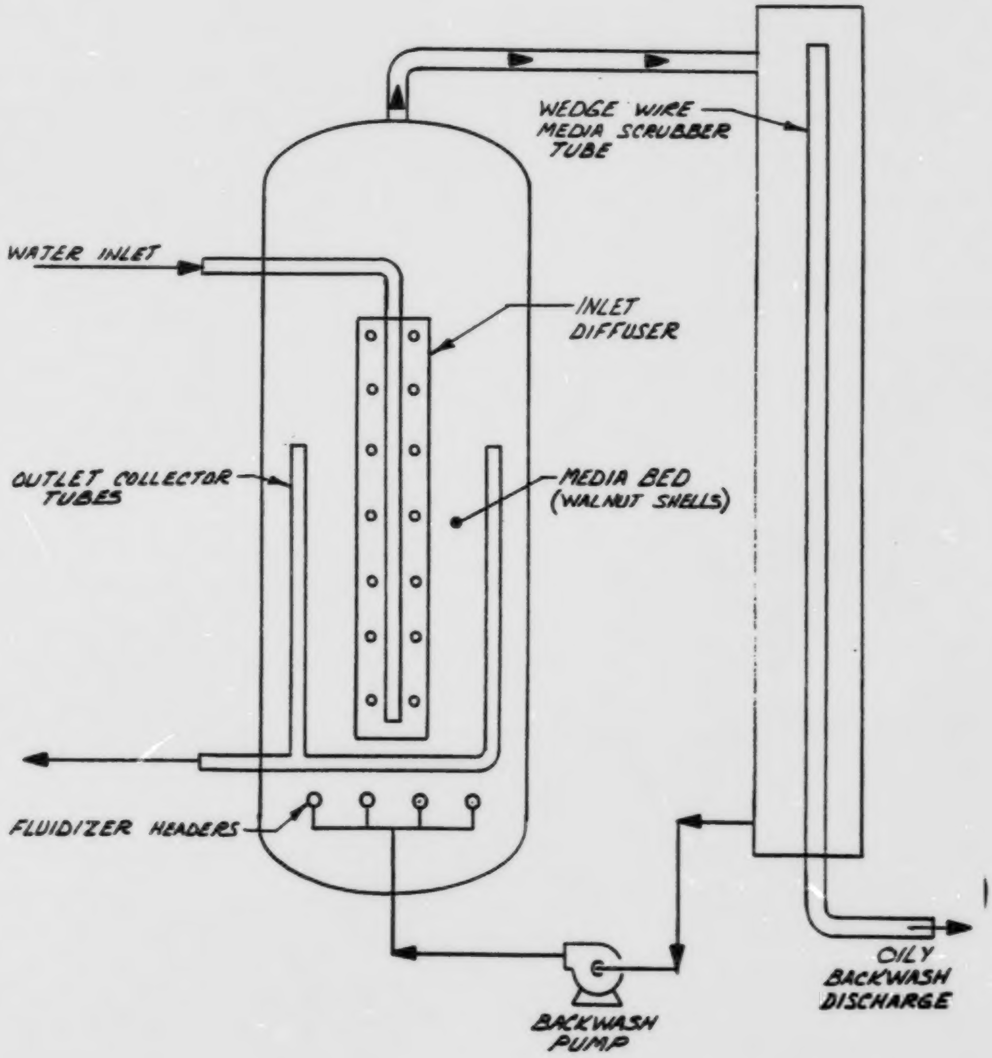

WEDGE WIRE MEDIA SCRUBBER TUBE
WATER INLET
INLET DIFFUSER
OUTLET COLLECTOR TUBES
MEDIA BED (WALNUT SHELLS)
FLUIDIZER HEADERS
OILY BACKWASH DISCHARGE
BACKWASH PUMP

Figure 12
Typical Water Reuse Plant

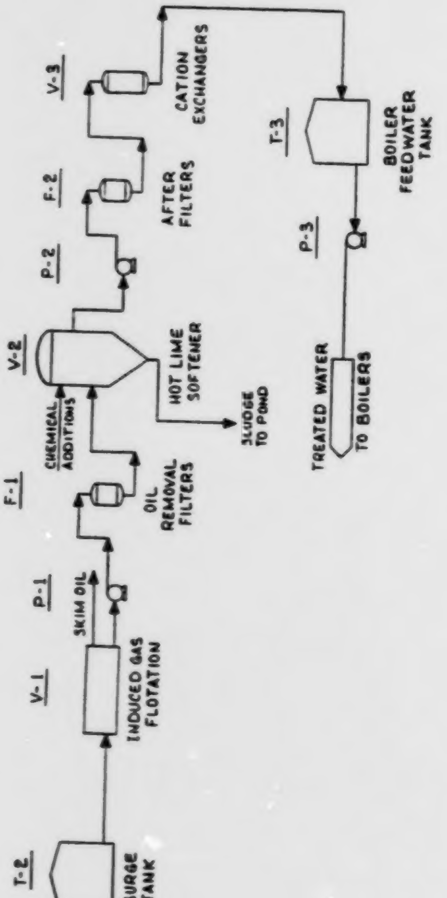
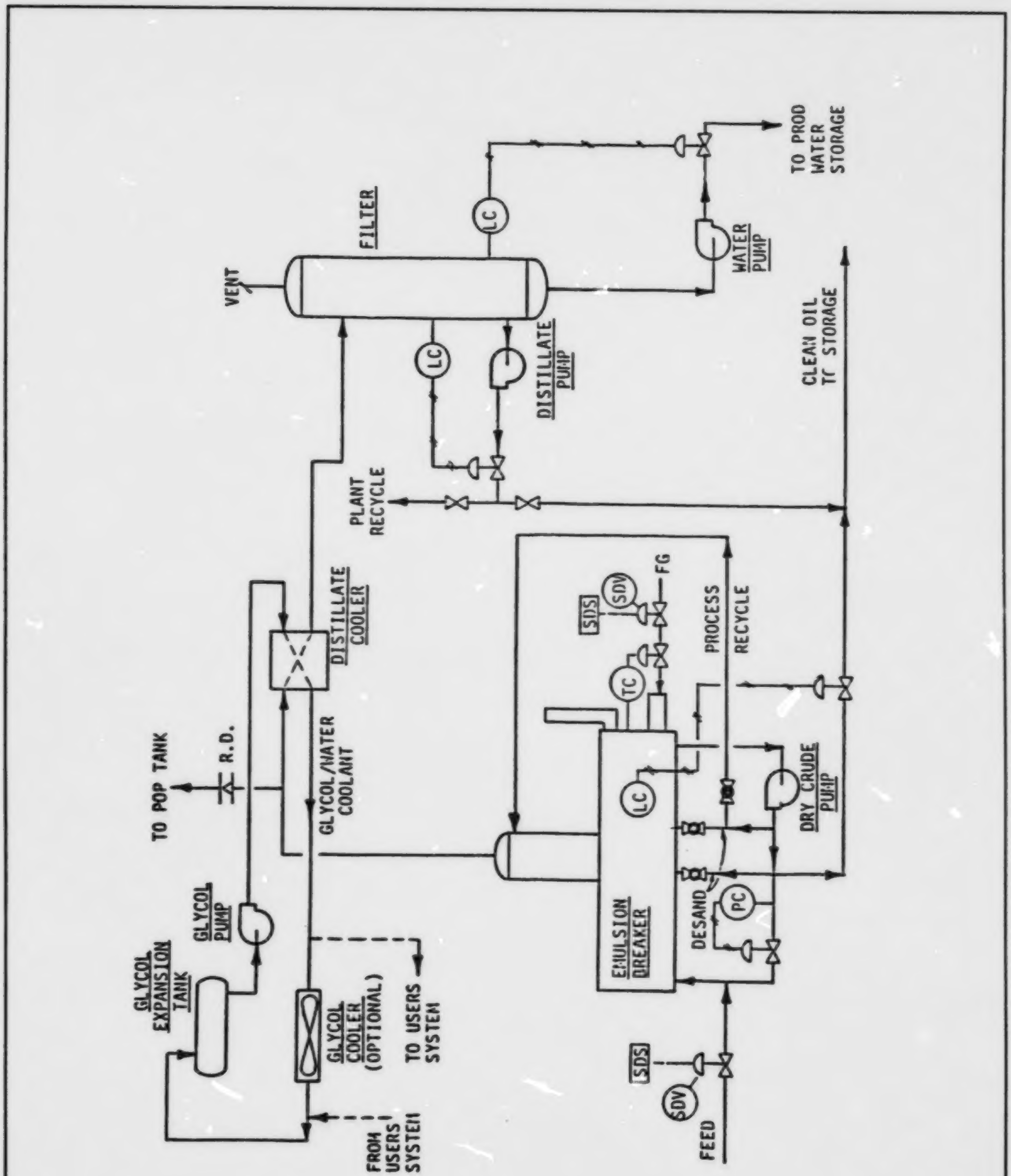

PRODUCED WATER
T-1
SKIM TANK
SKIM OIL
T-2
SURGE TANK
V-1
INDUCED GAS FLOTATION
SKIM OIL
P-1
F-1
OIL REMOVAL FILTERS
CHEMICAL ADDITIONS
V-2
HOT LIME SOFTENER
SLUDGE TO POND
P-2
F-2
AFTER FILTERS
V-3
CATION EXCHANGERS
T-3
BOILER FEEDWATER TANK
P-3
TREATED WATER TO BOILERS

Figure 13
Colt Emulsion Breaker Typical Flow Diagram



FILTER
VENT
LC
WATER PUMP
TO PROD WATER STORAGE
DISTILLATE PUMP
LC
CLEAN OIL TO STORAGE
PLANT RECYCLE
DISTILLATE COOLER
FG
SDV
SDS
TC
PROCESS RECYCLE
TO POP TANK
R.D.
GLYCOL/WATER COOLANT
LC
DRY CRUDE PUMP
EMULSION BREAKER
DESAND
PC
GLYCOL EXPANSION TANK
GLYCOL PUMP
GLYCOL COOLER (OPTIONAL)
TO USERS SYSTEM
FROM USERS SYSTEM
SDS
SDV
FEED

29

PILOT EXPERIMENTS OF STEAM INJECTION AT SHANJIASI HEAVY OIL FIELD

Huang Shi
Shengli Oilfield Geology Institute

ABSTRACT

This article describes the characteristics of Shanjiasi reservoir and presents the geological study, physical modeling and numerical simulation to investigate the feasibility of thermal recovery of the reservoir. Experiments in cyclic steam stimulation were conducted at the Shanjiasi thermal recovery pilot. Pilot performances and existing problems of the pilot are discussed. Suggestions are made to further improve thermal recovery efficiency at Shanjiasi.

INTRODUCTION

Shanjiasi oilfield is located at the northern part of Shandong Province (see Figure 1). The oil is very viscous. Production by conventional method was low. In 1983, a steam injection pilot was developed over a 0.5 Km^2 area at Shan #2 fault block in the eastern part of the oilfield (Figure 2). The pilot covers an area with 6.21 million tons of oil in place, and consists of a 9 inverted 5 spot patterns and 25 experimental wells with 141 meter well spacing between a producer and an injector. Cyclic steam stimulation began in September, 1984 and the production performance of the pilot has been quite good.

RESERVOIR CHARACTERISTICS

The top of the formation is 1100 meter below surface (Figure 3). Its lithology is medium to coarse grained sandstone containing dark brownish pebbles. The oil bearing formation is quite thick, with average effective thickness of about 56 meters and maximum thickness of 75 meters. It consists of very few intervals, usually only 1 to 2 intervals. A number of intercalations of sands and clay are found in the oil bearing formation. The ratio of effective thickness to gross thickness is 0.87. The oil bearing formation is a unconsolidated sandstone formation containing 3.6 % clay, 83.4 % of which is montmorillonite according to X-ray diffraction analysis. Its cationic exchange capability is only 0.029 mg mole/gm, which is too small to be of concern for the steam injection operations.

Reservoir properties is quite good, with porosity ranging from 32 to 35 %, permeability 1.418 μm^2 and oil saturation 62 to 68 %. The formation is bounded at the bottom by a water zone, with oil water interface located at 1,180 to 1,200 meters. The initial formation pressure is equivalent to hydrostatic pressure. The initial oil/gas ratio is only 8.1 m^3/ton. The saturation pressure is lower than 4.66, and the surface differential saturation pressure is large. Formation temperature is high; it is between 54 and 57° C at 1,100 meter deep. Temperature gradient falls between 3.7 and 4 °C/100 meters. The formation rock is water wet. The properties of degassed crude are summarized as follows,

Specific gravity:	0.98-.99
Viscosity:	10 Pa.s at 50° C
Sulphur Content:	0.616 %
Resin Content:	19.84 %
Asphaltent:	1.7 %
Nickel:	47.5 mg/g
Vanadium:	2.28 %

Distillation Fractions:

<200° C:	1.38 %
200-350° C:	10.64 %
350-450° C:	17.24 %
450° C:	69.41 %

Because the thickness of the reservoir at the pilot area is enormous, the horizontal and vertical heterogeneity of the formation would be a potential problem for steam injection process. From the analysis of the available information, permeability and crude oil viscosity varies widely in the formation. Take Shan 2-11 well as an example, the experimental interval is an 85.2 meter thick single oil bearing interval. Permeability of the interval is 0.953 μm^2, with maximum value reaching as high as 15,217 μm^2 From micro analysis of crude oil in small core section, oil viscosity at 100 °C is 1 Pa.s and for some core, it can be as low as .135 Pa.s. Permeability and viscosity also show great variations between two wells in the same pilot area. For example, average single well permeability is 5 at the maximum and 0.523 μm^2

the minimum; maximum degassed crude viscosity is 22.88 Pa.s and minimum 8.984 Pa.s. If precaution is not taken to address the problems associated with the formation heterogeneity, steam channeling would occur prematurely. Production performance would be affected by poor oil sweep efficiency and disturbance coefficient

FEASIBILITY OF THE THERMAL RECOVERY PROCESS

i) From the Formation characteristics:

The formation is thick, its connectivity is excellent and its oil saturation and porosity are high. With 220,000 tons of oil per Km^2 of oil bearing formation, the oil reserve is considered high. All these characteristics of the reservoir are conducive to high production.

Crude oil viscosity is strongly influenced by temperature as shown in Figure 5. Viscosity drops 50% for every 10 degree C drop in temperature before the viscosity-temperature curve levels off at around 90^o C, as shown in Figure 6. According to the rheological study of the crude oil, the crude oil exhibits properties of Bingham plastic fluid at temperature below 90^o C and a Newtonian fluid at temperature higher than 90^o C. The heavy crude oil becomes mobile in the formation and wellbores as its viscosity is drastically reduced by the injection of high pressure and high temperature steam. This constitute a major mechanism for increasing production by the thermal recovery processes.

As the formation is deep, between 1,100 and 1,200 meters, and has not been depleted by any primary production process, the formation energy is sufficiently high. The hydrostatic pressure at the core of the formation is 112.8 kPa. The high formation pressure at the beginning of the thermal recovery process helps the heated oil to move faster and in greater quantity. High production can be expected when the differential production pressure is maintained.

The oil bearing formation is an unconsolidated highly permeable sandstone. The high permeability permits steam to be injected to the formation and heated oil to be produced from the formation at a high rate. This is one of the main reasons why production from the cyclic steam stimulation is effective.

There are, however, factors that are detrimental to thermal recovery processes such as wells being too deep, formation heterogeneous, bottom water zone causing large heat loss, steam channeling and water production. The problems are to be solved by new technology before the processes is viable for field production applications.

ii) From Physical Modeling and Numerical Simulation:

Slimtube test showed that Shanjiasi heavy oil could not be economically recovered with conventional cold water injection method because of poor oil sweeping efficiency. The results also indicated that recovery by steam injection was more effective.

Laboratory experiments were also carried out using a high pressure scaled physical model to simulate an inverted 5 spot well pattern production scheme. The following production conditions were simulated in the test: 150 meters well spacing, 240 tons/day optimum steam rate, optimum perforation location and openning (perforation for production and injection are 1/8 and 1/4 of well length from the bottom), and 61.5 % steam quality at wellhead. The laboratory experiments indicated recovery could reach 34.5 % and cumulative oil/steam ratio 0.223 by the production year 12.5.

Results of the numerical simulation by the Petroleum Research Institute indicated that cyclic steam stimulation process could recover 24.2% of oil with a .24 cumulative oil/steam ratio at the end of the sixth cycle when formation pressure drops to 3.92 MPa and temperature rises to 61-65^o C at the end of production year 6.6. Production is continued for another 6 years with steam drive process which recovers an additional 20 % of oil with the cumulative oil/steam ratio of 0.21. For the two processes combined, total recovery is 44.2 % , oil/steam ratio is 0.59, and average recovery is 3.5% per year. Numerical simulation of the Shanjiasi pilot was also conducted by the SST company in the U.S. Results from the SST's simulation are slightly different from that of the Petroleum Research Institute due to the different parameters and conditions used in the simulation. However, the 59 % total recovery projected by SST for the two processed combined is nonetheless quite impressive.

Pilot Production by Cyclic Steam Simulation

From September 1984 when steaming of the first well began until the end of 1986, a total of 42 steaming cycles and 40 production cycles were performed on the 27 wells with the successful rate of 95.2 %. Steam generator outlet pressure dropped from 15-17 MPa during the early stage to the current 11-15 MPa. Average steam injection intensity was 72 tons/day/meter reservoir thickness and the maximum value was as high as 184 tons/day/meter. The steaming parameters are tabulated in Table 2. Production had noticeably been improved since start-up. The three wells that were put into production in 1984 were able to flowback and yield over 100 tons of oil daily from their 18 cm wellheads during the early production stage (maximum daily production was 191 tons). Flowback period lasted about a month(maximum was 80 days) and produced 60-108 tons of oil daily on the average, as shown in Figure 7. For the wells that were put into operation since 1985, they experienced difficulty in flowing back due to high wellhead pressure. Consequently, daily production rate dropped from 90 tons/day during the initial period to the current rate of 48 tons/day. By the end of 1986, the pilot has injected a cumulative 163,000 tons of steam and produced 415,000 tons of oil. Oil recovery was 6.7 % and annual recovery rates were 2.29 % in 1985 and 4.2 % in 1986 (Figure 8). Currently, the pilot had completed 16 first cycle operations on 16 wells and second cycle operations on 4 wells. Production data of these wells are tabulated in Table 3. Out of the 4 second cycle wells, only one well provided reasonable data for studying the effect of production cycle; the remaining three wells either were watered out or suffered low steam injection and their data are invalid for the study. Table 4 shows the comparison of production data between the two cycles for Well Jia-2-20.

The overall operating experience of the pilot has been generally positive during the past two years. It verifies the prediction and major conclusion from the geological study, physical modeling and numerical simulation that thermal recovery of the 1,100-1,200 meter deep Shanjiasi reservoir is feasible. However, the pilot experiments also revealed some operational problems such as steam channeling and high water yield. Among the four wells suffering from steam channeling since 1985, two experienced steam breakthrough which was characterized by short steaming period (4-10 days), low steam injection volume (1406-2350 tons), high propagate speed of steam front (daily average about 25-14 meters) and steamflood response prior to production. The other two wells only showed steamflood response but they experienced drastic rise in wellhead temperature, water content and liquid yeild. Production data from these wells are detailed in Tables 5 and 6. Steam channeling can be attributed to the following two major factors:

i) Steam channeling is caused by the presence of highly permeable thin streaks or formation fractures induced by high injected steam pressure. Coupling with high steam injection rate, steam channeling is liable to occur.

ii) A large pressure difference between an injector and a producer was directly responsible for the occurrence of steam channeling as indicated by Well Shan 2-9 during its first and second cycle production. During the first cycle injection, pressure difference from its neighboring well, Shan 2-1, was 6.49 MPa which caused steam channeling within a relatively short time. During the second steaming cycle, the pressure difference dropped to 1.49 MPa since well Shan 2-1 had been converted to an observation well. No steam channeling occurred as a result of the reduced pressure gradient.

Since 1986, eight wells had been observed to produce high water yield. These wells are mainly located in the south eastern region of the piloting area where the formation structure is lower. These water-out wells can generally be divided into two categories . The first category , under which three of the wells can be classified, showed high water production soon after start-up, before significant amount of oil was produced. The second type of well watered out only after it had produced 15-20 thousand tons of oil over a prolonged production period of several months or after the first production cycle had been concluded. Connate water from the region usually contains high concentration of calcium chloride. Total suspended solid is between 14,000 and 16,000 mg/liter. The main reason for high water yield from the first type of well was perhaps due to poor well completion allowing the bottom connate water to enter into wellbores. The reason for the second type of well may be due to the drop in formation pressure as the formation is depleted over the extended period of time, allowing the bottom connate water to invade the pay zone. The above reasonings are merely speculation awaiting further verifications.

CONCLUSION

Pilot experimentation of cyclic steam stimulation process indicates reasonably high oil production from the Shanjiasi heavy oil reservoir which cannot possibly be recovered by conventional methods. Results of the pilot testing have been quite encouraging and verify the conclusion obtained from the geological study, physical model and numerical simulation, all of which indicate that cyclic steam stimulation is feasible for recovering the 1,100- 1,200 meter deep heavy oil reservoir.

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- 3. Botmann, F.H., "Advance Crude Oil Recovery Technology", 1885 June
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Table 1
Viscosity-Temperature of Degassed Crude From Well Shan 2-1 and 2-3

Shan 2-1 Well		Shan 2-3 Well	
Temperature C	Viscosity x 1000 Pa.S	Temperature C	Viscosity x 1000 Pa.s
62	6980	41	12137
70	3570	60	2048
80	1637	77	592
90	808	100	182
100	452	121	91
110	273	143	53
120	174		

Table 2
Steaming Parameters for Field Testing of Cyclic Steam Stimulation and for Numerical Simulation

		Numerical Simulation	
	Field Testing	Petroleum Institute	American SSI Co
Cycle Injected Steam Quantity, Tons	3000- 4000	4500	3200
Wellhead Steam Quality, %	60	72	75
Injection Rate Ton/Day	220-240	* 220-250	216
Soaking Period, Day	3-4	3-4	4

Note: *—50 Tons during first cycle and 220-250 thereafter.

Table 3
Production Data at the Conclusion of First and Second Cycles

Cycle	1	2
Number Of Well	16	4
Cumulative Steam Injected, Tons	3575	3946
Cumulative Oil Produced, Tons	11508	8845
Oil/Steam Ratio	3.22	2.24
Steam Injected/Reservoir Thickness Tons/Day.Meter	72	89
Oil Produced/Reservoir Thickness Tons/Day.Meter	338	199
Number of Well Produced:		
Over 20,000 Tons Oil	3	1
10,000-20,000 Tons Oil	5	
< 10,000 Tons Oil	8	3

Table 4
Comparison of Production Between First and Second Cycles at Well Shan 2-20

Cycle	**First**	**Second**
Steam Injected, Tons	1643	4434
Oil Produced, Tons	6715	22930
Oil/Steam Ratio	4.09	5.17
Water Produced, Tons	349	1746
Water/Steam Ratio	0.21	0.39
Steam Injected/Reservoir Thickness, Tons/Meter	47	127
Oil Produced/Reservoir Thickness, Tons/Meter	190	650
Daily Oil Production, Tons/Day	59	69
Production Day	113	332

Table 5
Production Conditions at Steam Channeling Wells During First Production Cycle

Injector	Sham 2-9	Sham 25-9	Sham 2-5	Sham 21-17
Producer	Sham 2-1	Sham 2-24	Sham 2-3	Sham 2-7
Well Spacing, Meter	100	141	141	165
Steaming Date	85/02/08	86/08/26	85/05/19	86/11/02
Steamflood Response Date	85/02/11	86/08/28	85/06/08	86/11/13
Steam Breakthrough Date	85/02/12	86/09/05		
Steam Injected, Tons				
-At Steamflood Response		722	4866	1558
-At Steam Breakthrough	1406	2390		
At Injectors:				
-Steam Quality, %	63.4	74.4	68.3	50
-Steaming Rate, Tons/Hour	18.1	16.6	18.3	7.8
-Wellhead Pressure, Mpa	15.7-17.3	10-12.4	12.3-17.3	10-17
At Producers Before Steam Breakthrough:				
-Well Temperature, C	65	78	70	42
-Water Content, %	0	15	22.4	36
-Liquid Production, Tons	91	75	93	77
At Producers After Steam Breakthrough:				
-Well Temperature, C	134	97	90	114
-Water Content, %	77	93.1	48	52.7
-Liquid Production, Tons	45	114	107	109

Table 6
Pressure Difference Between Steam Channeling Wells

	Steaming Pressure Mpa			Prod'n#	Pressure#
Injector	Wellhead	Bottomhole	Producer	Pressure	Difference
Shan 2-9		16.2	Shan 2-1	967	649
Shan 2-9*		12.2	Shan 2-1	1069+	149
Shan 25-9	9.8		Shan 2-24	686-402	294-579
Shan 2-5		12.0	Shan 2-3	618	584
Shan 21-17	15.7		Shan 2-7	888	681

Notes: #—Pressure in KPa

+—Hydrostatic Pressure; All others in the column are flowing pressure.

*—Second cycle data; All others are first cycle data.

Figure 1
Geographic Position of Shanjiasi Area

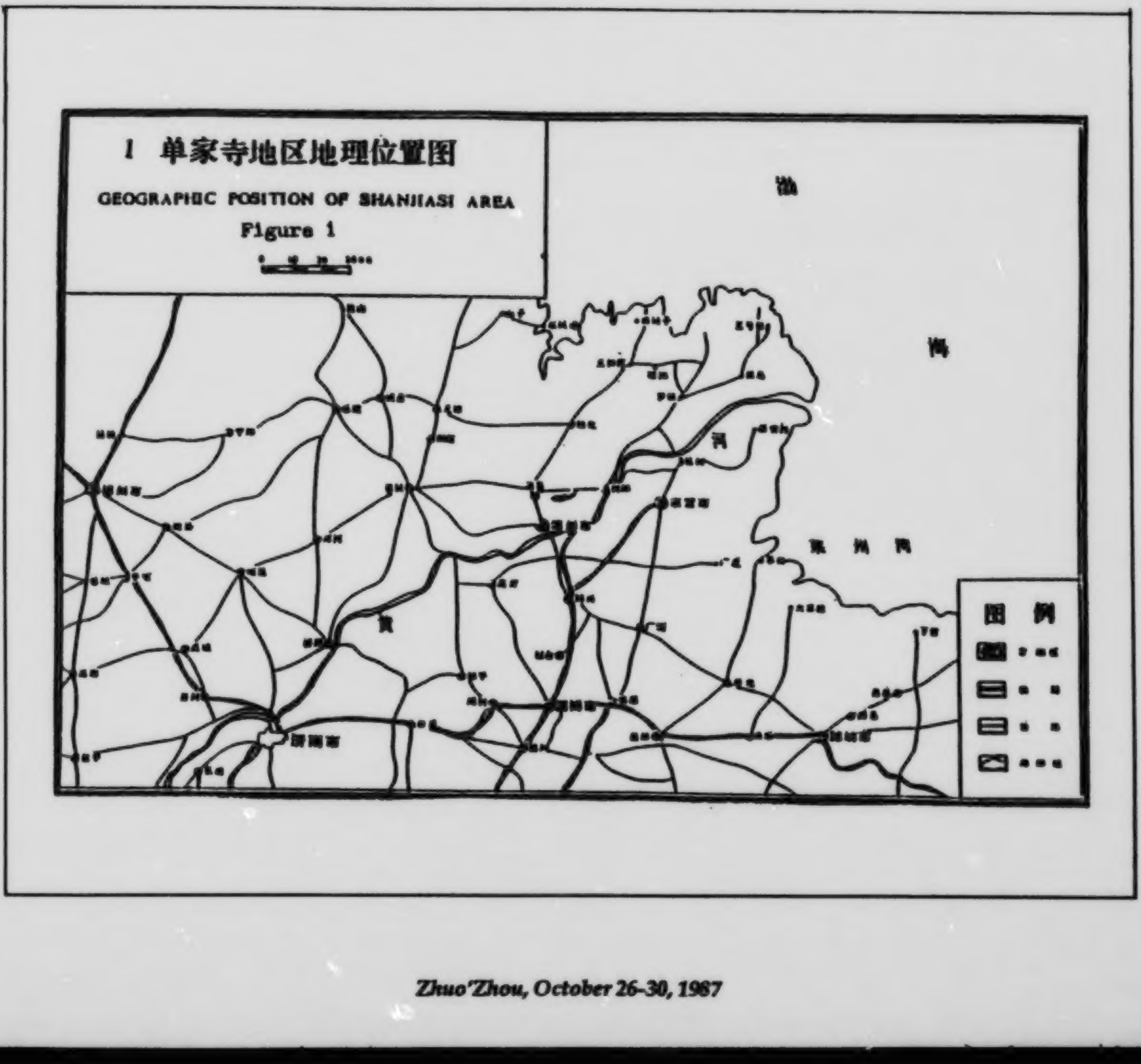

1 单家寺地区地理位置图
GEOGRAPHIC POSITION OF SHANJIASI AREA
Figure 1
渤
海
河
黄
莱 州 湾
图 例

Figure 2
Shanjiasi Oil Field - Shan #2 Fault Block Steam Injection Pilot

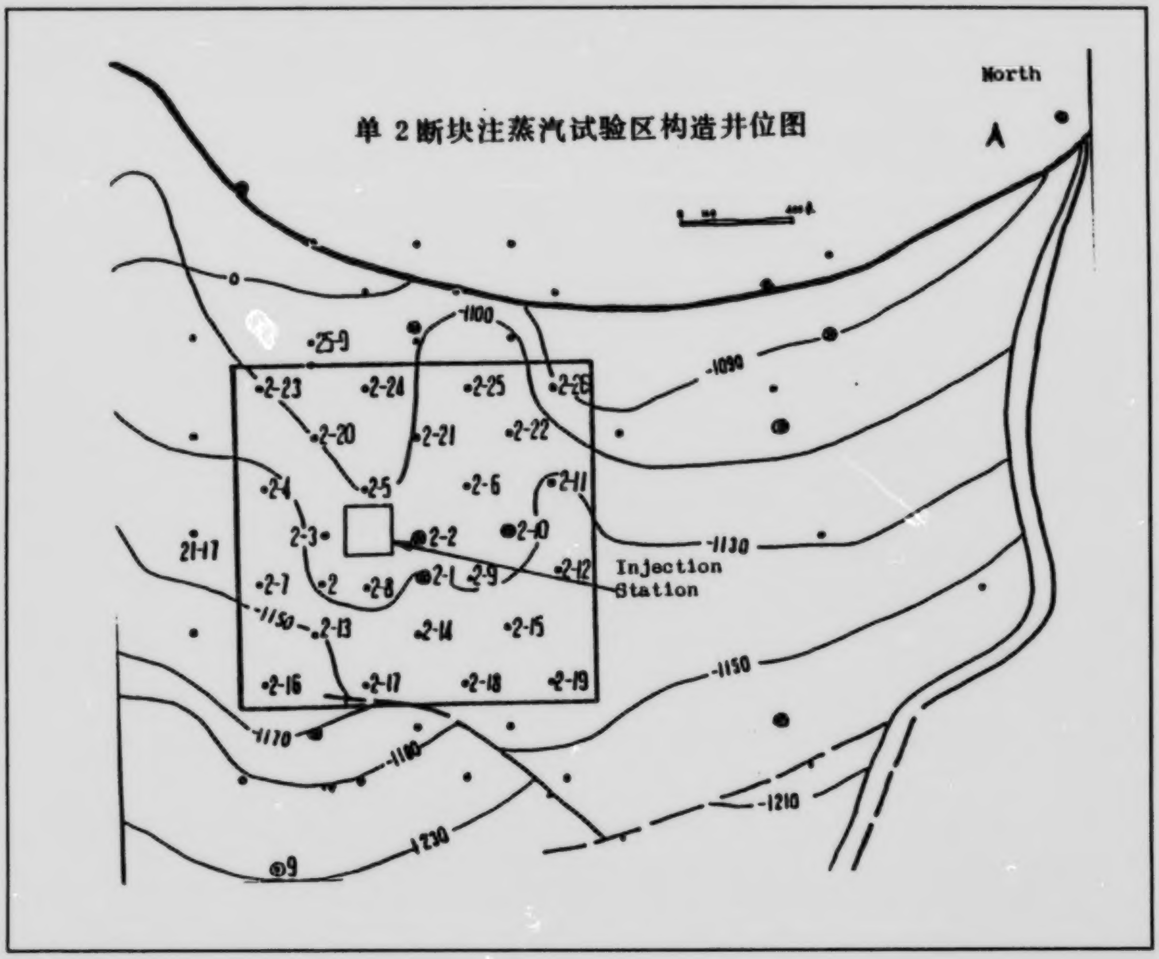

单 2断块注蒸汽试验区构造井位图
North
0
-1100
-1090
-1130
-1150
-1150
-1170
-1180
-1210
-1230
25-9
2-23
2-24
2-25
2-26
2-20
2-21
2-22
2-4
2-5
2-6
2-11
2-3
2-2
2-10
21-17
2-7
2
2-8
2-1
2-9
2-12
2-13
2-14
2-15
2-16
2-17
2-18
2-19
9
Injection
Station

Figure 3
Cross Section of Shan 2 Fault Block in Shanjiasi Oil Field

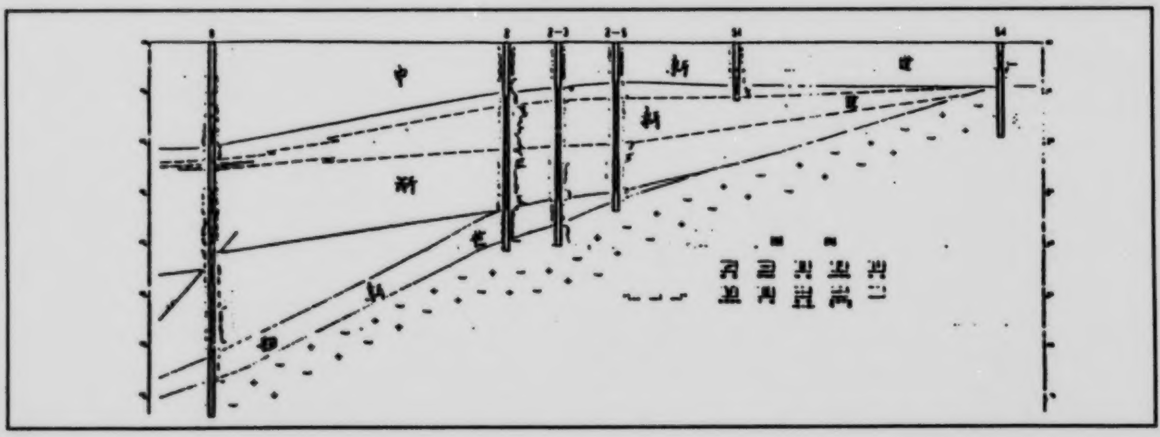


Figure 4
Columnar Section Showing Core Description of Well Shan 2-1

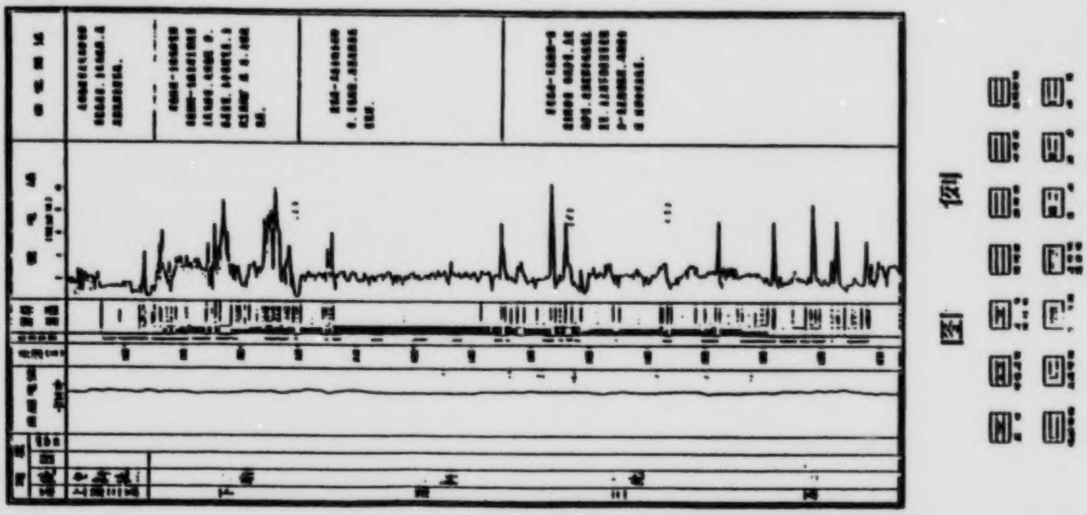


Figure 5
Viscosity-Temperature Curves for Crude From the Shanjiasi Pilot

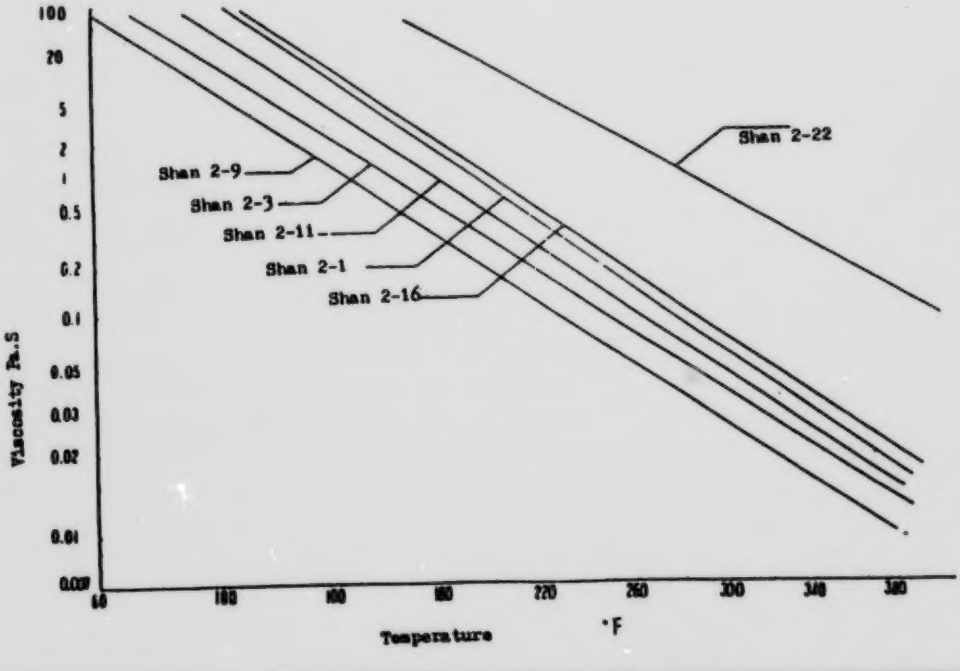


Figure 6
Well Shan 2-1 Crude Viscosity-Temperature Data

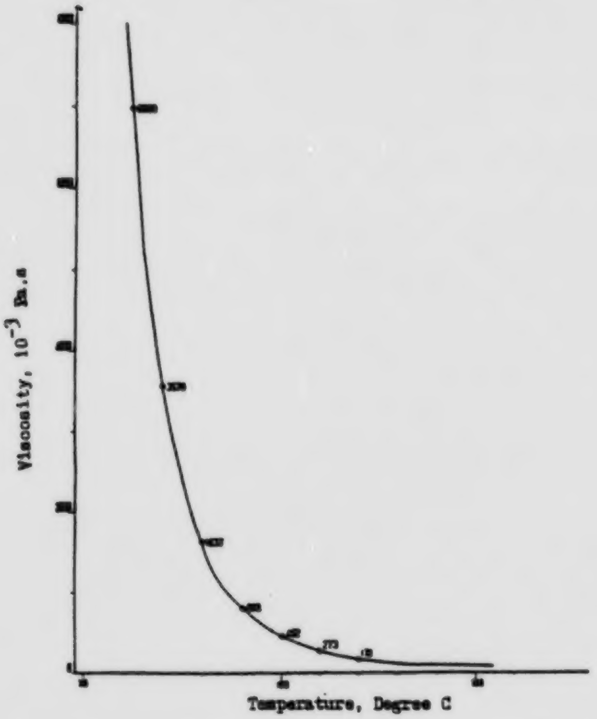


Figure 7

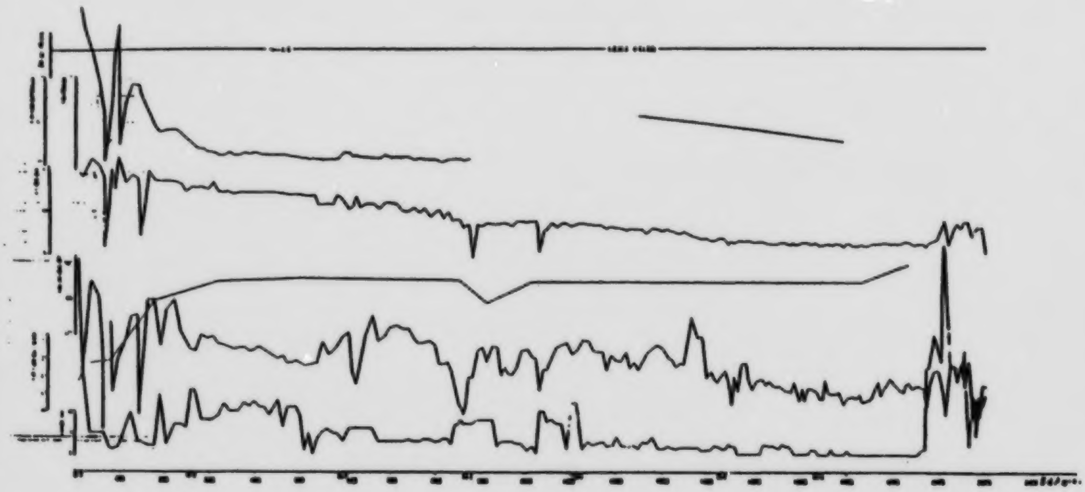
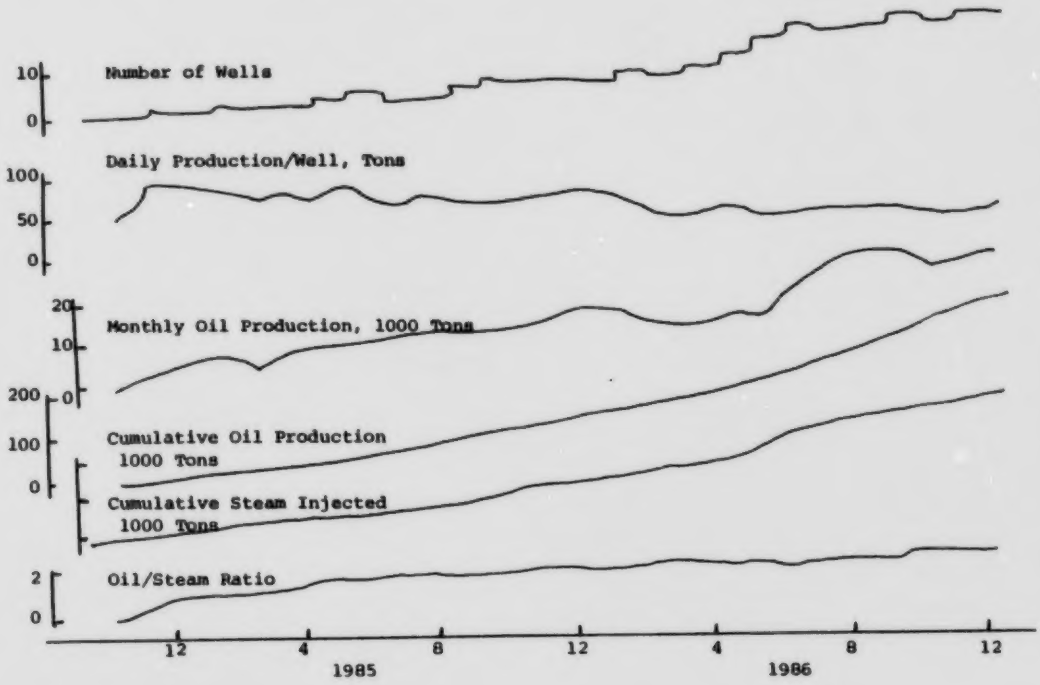


Figure 8
Production Data from the Shanjiasi Thermal Recovery Pilot



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DESIGN AND OPERATION OF A STEAM PILOT

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H.S. Chhina

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I. INTRODUCTION

Pilot projects have become a frequently used method of developing the technology and operational experience necessary to proceed with commercial scale in situ recovery projects.

Within the province of Alberta, Canada there have been a total of 146 projects that have received experimental or pilot status from the provincial regulatory agency. In many cases there has been a series of projects by the same operator on the same lease. For example, Esso has had 4 pilot projects on their Cold Lake lease, the first being in 1964 while the most recent, Leming, has been incorporated into the current commercial operation.

The majority of the above referenced projects have been based on steam related recovery processes, while the remainder use combustion. Although the scope of this paper will be restricted to pilot projects of steam based recovery processes, there should also be application to other types of pilot projects.

There are four of these steam pilot projects that have progressed to commercial scale production: Esso - Cold Lake, BP - Wolf Lake, Shell - Peace River and Suncor - Fort Kent (Figure 1) . For the purpose of this paper, a commercial scale project is defined as producing in excess of 1000 m^3/d of bitumen and having more than 100 active wells. This paper will also use the term demonstration plant for projects with approximately 300 m^3/d of bitumen production and approximately 50 active wells. Pilot plants will be considered to typically have 25 or fewer active wells.

The apparent limited success of progressing from a pilot project to a commercial operation can usually be explained by a combination of lower than expected production rates and net oil prices. Proper management of a pilot project can improve the possibility of increased production rates and reduced operating costs. Influencing and predicting oil prices are beyond the scope of a pilot project and also this work.

It is intended that this paper provide a format for improved design and operation of steam pilots. The content is derived from AOSTRA's participation in 8 major steam pilot projects. The location of these projects are shown in Figure #1. Important features of these pilot projects are summarized in Figure 2.

Information on the planning, design, operation and evaluation of a steam pilot project will be presented. The discussion on planning will emphasize the essential coordination with commercial project information requirements. The sections on design, operation and evaluation will outline a systematic approach to managing such an operation. The theory presented will be illustrated by a number of examples.

II. ROLE OF STEAM PILOTS IN THE DEVELOPMENT OF HEAVY OIL AND OIL SANDS RESOURCES

Pilot projects are typically an integral step in the development of a commercial steam based recovery project. It is the requirement for information for the commercial project planning process that dictates the objectives of the associated pilot project. In more basic terms a pilot project is only required to provide information for the development of a commercial project. A flow chart of the development process for a commercial project is presented in Figure 3.

The first and most important observation from the flowchart is that a plan for a commercial project must be formulated prior to any consideration of pilot plant development, or any other information gathering activity. The plan should consist of a set of activities and the related supporting evidence for the components listed in Figure 4. This plan is developed from the set of available information. If the plan is considered acceptable then commercial development should proceed. The criteria to evaluate the acceptability of the commercial plan are not discussed in this paper.

If the plan is unacceptable, then there is an option of reformulating the plan with the same information and/or obtaining additional information. A number of loops through the complete planning process will usually be required prior to a final decision on commercial viability.

The function of a steam pilot project within this framework is to gather the information necessary for the commercial project plan.

Most commercial project developments could benefit from closer adherence to this flowchart. In particular there is a tendency to not regularly formalize the commercial project plan. This plan should be formally updated and reviewed annually. In addition there is a tendency to adopt new information into the commercial project plan without a complete evaluation within the planning process. Often an isolated alteration to the commercial project plan should be a revision of larger magnitude.

When a commercial project plan has been reviewed and is determined to be currently unacceptable, then a list of beneficial additional information can be prepared. The key here is to isolate the beneficial information. For example, if geological control is a problem, then it is unlikely that additional numerical simulation would be of much benefit. From this list, a plan to obtain this information can be generated. There are a number of different methods available to obtain a particular type of data. Each specific method of data gathering has a range of suitability, depending on the type of data to be acquired. Refer to Figure 5 where a matrix of the suitability of data gathering methods with various data types is presented. Pilot plants are one option that is frequently selected, especially when a new location and/or reservoir process are important factors. Other types of data gathering methods are useful, depending on the specific data type. The common practice is to assign the requirement of a particular data type to a specific set of data gathering methods. For example the fundamental reservoir process concept may be developed from the combination of a consultant, lab tests and a pilot project.

The formal assignment of data gathering methods to data types reduces the possibility of inadvertently omitting or duplicating data gathering requirements. The remaining sections of this paper will focus on the use of pilot projects as a data gathering method.

In summary the development process for a commercial project specifies the set of information to be obtained from a pilot project(s) and also from other sources. Proper management is achieved when;

1. A formal commercial project plan is prepared, updated and reviewed annually.
2. Input of new data to the commercial plan is evaluated for all possible implications.
3. A list of information requirements beneficial to the commercial plan forms the basis of data gathering activities.
4. Careful matching of the data gathering methods to the type of data to be gathered will optimize the development process. When this matching is formally documented the possibility of mismatches occurring is reduced.

III. FORMULATING OBJECTIVES FOR A STEAM PILOT

Given a data gathering task defined by the commercial project development process the first stage in the pilot project development is to set the objectives. These are frequently very simple but are usually very effective when used as a control mechanism. A flowchart for the development of pilot objectives is shown in Figure 6. The objectives are more than a duplication of the information requirements of the commercial planning process. For example, the commercial planning process may require the identification and verification of a reservoir process for a particular field that results in a calendar day oil rate (CDOR) of 10 m^3/d per well and a steam oil ratio (SOR) of 5.0. A condensed version of the resulting pilot plant objectives might be:

1. Find a reservoir process for the XY field that produces a CDOR of 10 m^3/d per well an an SOR of 5. 0.
2. The pilot project should test the x and z processes on 7 spot and 5 spot patterns respectively.
3. The total project life is 5 years, 4 years for operation and 1 year for design and construction.
4. The actual well performance will be history matched by a numerical model which will provide the final predictions to the commercial plan.
5. A budget of $XXXX has been allocated.

Such a simple set of objectives can serve to focus the subsequent pilot activities. The objectives are most useful if they are formally and consistently updated. It is usually convenient to divide the pilot project execution into four components; planning, construction, operations and evaluations. Each of these components will be addressed in turn in the following sections.

IV. PLANNING PROCESS FOR A STEAM PILOT

The first phase of the overall pilot planning process is shown in Figure 7 and involves the preparation of a scope statement which serves as a cornerstone of the planning process. It is particularly important for the initial estimates of reservoir performance to be made at this point. This document enables all members of the project planning team to work from the same basis.

It is the planning phase of the project where the major design activities occur. These design activities may be conveniently categorized into three major areas.

1. Reservoir Process

When a pilot project is initiated, the reservoir usually requires a comprehensive formation evaluation. This involves conducting lab tests, field tests and numerical modelling. The lab tests consist of the determination of fluid properties and rock properties. The field tests that can be conducted are described in the reservoir evaluation section.

Fluid properties include data such as viscosity, density and gas solubility, both as a function of temperature and pressure. The rock/sand properties include porosity, absolute horizontal and vertical permeability and oil and water saturations. The porosity and the fluid saturations can be determined from open/cased hole logs, or from core analysis. Coreflood tests are also conducted at various temperatures to determine the oil, water and gas residual saturations and the relative permeability at the end points. Sometimes an entire set of relative permeability curves are determined for the water-oil and gas-oil system, rather than just end points.

It is important to determine the fluid properties of at least a few initial state samples of oil, water and gas. The injection of fluid (especially steam and air) can cause significant changes to the fluid properties. It is important to quantify and compare these changes in fluid properties over time. For instance, bitumen viscosity has been found to both decrease and increase with time. Mineral reactions in the formation and chemical alteration of the reservoir fluids can induce new gases. The evaluation of the produced gas composition and production rates depends upon the establishment of initial values.

Preliminary numerical modelling scoping studies are sometimes conducted using the initial reservoir and fluid properties, to assist in the selection of the best recovery process. Sometimes, when the necessary data is available to conduct a numerical simulation study, simple analytical models can be used to determine an injection and production forecast. A production forecast along with an estimate of the in place bitumen reserves can be used to conduct a preliminary economic analysis of the pilot project.

2. Well Design

After a specific set of objectives has been derived from the overall pilot objectives, the well design process requires the investigation of the following subjects:

(a) Vertical/Deviated/Slant Wells: Vertical wells are most applicable in shallow formations with large well spacing. Typically when wells are less than 400 m in depth and have a spacing greater than the depth. Slant wells are applicable at intermediate depths of 300-700 m when the well spacing is approximately equal to the depth. Deviated drilling generally covers all other combinations of spacing and depths.

(b) Mechanical Integrity in Thermal Operations: Casing strength and coupling type are important considerations, particularly in formations prone to movement. Cement properties should also be investigated. Thermal expansion of downhole equipment must be allowed for. The thermal integrity of all seals and elastomers must be evaluated.

(c) Production Performance: The tubing and pump should be capable of meeting the requirements of the reservoir process. Most AOSTRA affiliated projects incorporate 88. 9 or 73. 7 mm tubing and the largest pump diameter available. Sumping of the pump has proven very beneficial.

(d) Sand Control: The size and type of sand screens may dictate the diameter of the casing. Sand production is very site specific, actual field tests are required to confirm this. Sand control techniques may be evaluated to a limited degree in laboratory testing.

(e) Expected Workover Frequency and Severity: New and more complicated designs will probably result in larger workover expenditures. Inadequate designs will also prove costly in terms of data loss.

(f) Bottomhole Instrumentation: Can complicate the well design significantly. Details must be carefully considered.

(g) Wellhead: Each situation requires a unique evaluation. Bottomhole instrumentation can severely complicate the wellhead design. Start-up, shut-down, and workover requirements must be accommodated.

(h) Clearances: All components must be able to be easily installed and removed from the wellbore. Specifications for maximum dogleg severity must be set and verified. Commonly used values are 6°/30 m.

(i) Production/Injection Intervals

Should be selected to avoid casing collars and shale zones, and high transmissibility water and gas zones.

3. Surface Facilities

The many different systems encompassed under this subject preclude a detailed discussion in this paper. Only some major points will be provided:

(a) Steam Generation: Proper sizing for a pilot is important. The peak demand requirements must be accommodated. Oversizing is also a potential problem. For example, on one AOSTRA project with a 50 GJ/hr steam generator, the reservoir process at times required only 50 m^3/day of steam, or 10% of the rated output of 500 m^3/day. Since the generator could only be turned down to 200 m^3/day, the venting of steam was necessary. In addition to the higher fuel costs, there was a significant effort expended to minimize the blowdown, particularly the adverse consequences during winter operations. The steam generator should also be capable of exceeding the formation fracture pressure. A reliable control system is another primary objective.

(b) Boiler Water Treatment: Stainless steel valves and internals are recommended on water softening vessels and piping. Plastic fittings are acceptable on chemical feed service. Biocide treatment of the water source is recommended.

(c) Satellites/Manifolds: Grouping lines and services at the earliest common point is usually cost effective. This area should be enclosed if environmental conditions dictate.

(d) Gathering and Distribution: Account for the effects of thermal expansion. Provide for start-up capability on cold bitumen lines. Proper insulation is essential for winter operation.

(e) Production Treating Facilities: Design of an accurate test measurement system is important. Gas may have to be added to purge separators. Some form of free water knockout tank is essential to smooth flow fluctuations from the field. Most production treating systems on pilot projects are oversized as shown in Figure 8. This is usually detrimental to good operation.

(f) Produced Water Disposal: Low oil concentrations are required to prevent plugging of disposal wells.

(g) Utilities: In cold climates where heat tracing is required the system should be generously sized and capable of accurate flow distribution.

In the intermediate phases, there may be a series of plans as various alternatives are considered. It is important to consider many ideas at this stage, rather than suffer from too narrow a perspective later on.

The final result of the planning process is a formal pilot plan that is suitable for implementation.

V DETAILED DESIGN AND CONSTRUCTION

Once the pilot project plan has been prepared and approved, the first major activity is to perform the detailed design, construct the necessary facilities and drill the appropriate wells. Proper control of this phase is effected through the implementation of a project schedule and cost management. The detailed construction/design schedule is formulated during the planning phase and is based on a wide variety of engineering input. Foremost among these are the specific equipment requirements and environmental constraints. A typical, yet aggressive construction schedule is presented in Figure 9.

The environmental factors are important and include the proximity to access roads, drainage contours and surface soil types. In many instances the requirement to construct a long access road has significantly extended the anticipated construction phase; delays of 6 months are not uncommon. It is good practise to push road and lease construction to start as soon as possible, particularly when soil conditions severely limit the possible operating time frames. It is also important to not underestimate the engineering required to control surface soil conditions. Decisions to either clear poor soils, or build floating pads must be carefully considered. Foundation designs for pump jacks and storage tanks also require appropriate solutions. Since 10-20% of the capital cost of a pilot plant is typically associated with road and lease construction, a sizeable cost savings can accrue from the application of proper engineering.

The other engineering factor of major significance is the proper specification of equipment. Numerous delays in project startup have resulted from inadequately sized pumps, control valves, and also from improper electrical, instrumentation and data acquisition components. Test and group treaters are other units prone to missizing.

Frequently this missizing and improper specification is the result of changes in project scope subsequent to acceptance of the formal pilot plan. Proper communication must be maintained between the various parties during this often hectic time. A monthly review of the project plan can prove beneficial. The other common cause of improper specification is the lack of attention to detail during the bidding process. Even relatively simple components such as wellheads and pump jacks must be properly designed and specified.

The effective implementation of the construction schedule is very dependent upon proper supervision and cost control. This is particularly important when unforeseen problems arise. Here there is need for rapid consultation with the design team and immediate implementation of the anticipated solution

Adoption of a phased startup has also proven successful in maintaining construction schedules. In this technique, individual units of the plant are placed in operation once they are completed, rather than waiting for a simultaneous startup. On a recent AOSTRA project, the early startup of the steam generation unit was judged to have saved several weeks from the schedule.

VI. EVALUATION TECHNIQUES

The process for effective evaluation of a pilot project starts with observations and measurements of events in the field as shown in Figure #10. Formal documentation of this data is imperative. Weekly, monthly and annual reports are effective means of documenting. Undocumented information is always lost or incorrectly retained.

All AOSTRA affiliated projects have computerized data acquisition systems for permanent storage of and improved access to all important project data. The system allows for a variety of sensors and input devices, but maintains a consistent operating system on all projects. The details of format and data types may vary between projects. A central master record is maintained by AOSTRA, in addition to the working versions resident with each project. Such systems are essential requirements for pilot projects of significant size or appreciable longevity.

Once the data and the observations have been obtained, the analysis by field, evaluation and management personnel can commence. This can involve.

- *summarization of events*
- *presentation of results and conclusions*
- *recommendations to alter the pilot objectives, plan or implementation.*

Specific techniques to analyze pilot project data have been employed and developed on AOSTRA affiliated projects. A brief summary of these are presented as follows:

■ 1. Reservoir Evaluation Techniques

Usually the primary objective of a pilot project is to investigate the applicability of a reservoir recovery process. In evaluating the success of a recovery process we are almost exclusively limited to using data from injection, production and observation wells. Determining reservoir performance under these physical constraints is a difficult problem. However, the proper use of field tests and numerical and analytical models can prove beneficial. Some of the more widely used evaluation methods for thermal projects are described as follows:

☐ *a) Transmissibility Tests*

Usually the very first test conducted, immediately after the wells are drilled, is a transmissibility test. The objective of the test is to determine the reservoir transmissibility (Kh/μ)
This parameter can then be used to estimate the injectivity of the reservoir below fracture pressure. If the reservoir is to be fractured, this parameter can be used to calculate the expected fluid leak-off from the fracture. In addition, this parameter is also used to set the initial relative permeability in numerical models. There are a number of different methods available for conducting this test, some of which are: constant rate injection, constant pressure injection, multi-rate and falling head tests. Normally for rich oil sands the injectivity to cold water is very low (0.1-0.25 $m^3/d.m.kPa$). Under these conditions it is generally difficult to conduct a con-

stant rate or constant pressure test. AOSTRA has found that the falling head test works reasonably well in underpressured reservoirs, and the test is operationally very easy to conduct.[1] The test involves filling up the wellbore with water with a downhole pressure recorder. Since most of the shallow oil sands deposits are underpressured, the hydrostatic head in the well results in positive flow into the formation. As the liquid level drops the pressure potential to flow decreases. The rate at which the liquid level drops is a function of the transmissibility.

☐ *b) In Situ Stress Test*

Another very basic test which has proven to be beneficial is an in situ stress test. The purpose of this test is to determine the minimum closure stress of the formation. Comparison of this with the vertical stress, which can be obtained from integrated density logs, will give a good initial estimate of the fracture orientation. For a closure stress greater than the vertical stress, a horizontal fracture in inferred and if the closure stress, is less than the vertical stress, then a vertical fracture is inferred. If fracturing is to be avoided, then the closure stress can be used to set the maximum operating pressure. To conduct a stress test, the formation is fractured for approximately a 3-5 minute period, at a constant injection rate. The results from the transmissibility test can be used to estimate a minimum rate that will be required to fracture the formation. The closure stress is determined from the pressure fall-off data, after the injection is shut-in.[2]

☐ *c) Pressure Transient Analysis*

This is probably the most widely used method for analyzing the changes occurring around the injection and production wells and in the reservoir. For a steam stimulation process, a pressure fall-off test at the end of steam injection can be conducted to determine:[3]

- *(i) reservoir transmissibility to steam*
- *(ii) skin damage*
- *(iii) average steam zone pressure*
- *(iv) steam zone volume*
- *(v) transmissibility of the cold zone ahead of the steam zone*
- *(vi) boundary/interference effects*

Pressure build-up tests are also routinely conducted on production wells. They provide information on the reservoir transmissibility, skin damage and the average operating pressure in the pattern. The amount of pressure change that occurs also gives information on the type of recovery mechanisms that are important. For example, initially in a steamflood there is a large pressure differential between the injector and the producer, which means that steam drag and steam drive are dominant mechanisms. However, if the pressure buildup during the test is smaller and close to the available gravity potential between the oil and the steam, then gravity drainage is a dominant mechanism. Initially in a steamflood the steam drag and steam drive dominate the process. As oil is produced and the transmissibility in the steam zone is enhanced, gravity drainage becomes the dominant mechanism.

☐ *d) Tracers*

As a result of the high mobility difference between steam and oil, channeling is very common during the operation of a thermal pilot project. Normally the well spacing for a cyclic steam stimulation project is designed to avoid interwell communication for a certain time period, which might vary from 1-5 years. However, in a steamflood it is essential to obtain interwell communication before good oil production rates can be achieved. In a multiwell steamflood pilot, fluid tracers are generally used to determine the communication paths between injectors and producers.[4] The rate at which a tracer is produced at a well can provide information on the type of fluid flow path. A material balance on the tracer from different wells can be used to quantify the difference in interwell communication among these wells. Sometimes the pilot is operating in more than one zone and it is important to know which well is producing from what zone. This information can be used to design or modify the injection strategy for the different zones.

There are a number of radioactive tracers that can be used for thermal projects, such as tritiated water, iodide-125, cobalt-57. Tritiated water is most commonly used, as it can be easily detected at low concentrations. Chemical tracers, such as the bromide ion solution, are used sometimes.

☐ *e) Seismic*

When a pilot is initiated in a new formation, it is important to characterize the geology of the reservoir, which will include shale streaks, variation in oil saturation, topography of the formation, gas zones and water channels. This information is useful in designing completion and production intervals and analyzing the recovery process. The degree of continuity of the shale streaks and water zones is helpful in deciding whether the formation is going to behave as one continuous zone, or whether a multi-zone process will have to be used. Recently, 3-D seismic has been used to detect the heated zone during the progression of a steamflood.[5] This technique has the promise of providing useful values for the areal and vertical conformance and depicts the effects of geological heterogeneities on steam conformance.

☐ *f) Well Logs*

Open hole logs are usually run on a routine basis on every well (eg. gamma, resistivity, SP logs). In a pilot project, quite a few wells are also cored routinely. The core can be used to calibrate the signals of the logs to specific geological zones. This enables the wells in a commercial project to be drilled without coring; a significant cost saving. Logs can be used to determine rich pay zones, shale barriers, streaks, breccia zones, gas zones and high water saturated zones. This data is useful in determining the gross pay, net pay, completion interval and the zones of interest. Carbon-oxygen logs can also be run on observation wells during the life of a pilot to determine which zones are being depleted. Well tracer logs (iodode-131) can also be run to determine the zone where fluid flow is occurring in the wellbore, and can be used to pick out channeling behind the casing.

☐ *g) Fluid Properties*

In a thermal project the hot fluids can have a significant effect on the mineralogical changes in the reservoir as well as on the oil. These changes can be monitored from the analysis of the produced fluids. For instance, in a number of oil sands areas the injected fluids react with minerals in the formation to produce carbon dioxide gas, which is detectable in the production wells. Sometimes reactions with oil can occur, such as visbreaking and aquathermolosis. These reactions result in breaking of the long oil chain molecules, resulting in the formation of constituents with altered viscosities. These changes can be detected by conducting oil analysis routinely. In addition, the chloride ion concentration in the produced water can be used to quantify the relative amounts of formation and injected water being produced. The initial formation water usually has a high chloride ion concentration and the injected water is fresh, with low chloride concentrations.

☐ *h) Analytical Calculations*

To design for the heat requirements of a reservoir and to make quick oil production calculations, analytical equations are used. Some of the most widely used analytical models for steam zone growth are the Marz & Langenheim,[7] Mandl & Volek,[8] Myhill & Steigeimer,[9] and Yortsos & Gavalas.[10] For hot water injection the Lauwerier equation is used.[11] These models can be used to determine the extent of a heated zone with time. All of them take the heat lost to the overburden and underburden into account. Some of them account for the amount of latent heat and the heat losses in the radial direction. Even though these models are simple and can be easily programmed on a calculator, they have been very successful in predicting the growth of a heated zone.

The prediction of oil production is generally more difficult because it depends on what the dominant recovery mechanisms are (ie. viscosity reduction, pressure drive energy, solution gas, thermal expansion, capillary imbibition, steam drag, gravity drainage). For heavy oil reservoirs with some initial primary production and with high initial reservoir pressure, viscosity reduction, pressure drive and solution gas drive have been found to be dominant recovery mechanisms. For steam stimulation, the Boberg & Lantz model[12] can be used to make predictions. However, in a thick reservoir, gravity drainage can also be significant, which is not accounted for in this model. For pressure depleted reservoirs, the Gontijo & Aziz model[13] is applicable. It accounts for the pressure drive from the injected heat and the gravity potential. Oil prediction models which take into account primary production have also been developed for steamflooding.[14]

Analytical models can be used for preliminary feasibility studies during the planning phase of thermal projects. Two of the principal parameters required for economic evaluations are the cumulative calendar day oil rate (CDOR) and the cumulative steam-oil ratio (SOR). These parameters can be easily estimated with these simple analytical models.

☐ *i) Numerical Modelling*

Numerical modeliing is routinely used for making more accurate predictions of a recovery process, and for investigating various operating strategies. A numerical model is more sophisticated, and usually requires a minimum of 2-3 months for completion. In addition, it is usually not worthwhile to initiate a simulation study unless good geological, reservoir and fluid data is available. This includes data such as:

☐ *(i) Geological - porosity, permeability, formation thickness, gross pay, net pay, gas zones, water zones, tight streaks.*

☐ *(ii) Reservoir - residual oil, water and gas saturations; pressure transient data, from pressure build-up tests, fall-off tests or multi-rate tests; two-phase relative permeability data for oil-water and gas-oil systems; thermal properties including heat capacities, thermal conductivity and thermal diffusivity.*

☐ *(iii) Fluid - oil viscosity and density as a function of pressure and temperature, gas solubility and its effects on viscosity and density.*

It is also important to know how these properties vary both areally and vertically throughout the reservoir.

Many of the above data requirements are not available at the commencement of a project. After some production history and reservoir data is available, a simulation study can be conducted to history match the field data, make predictions for the same process in the future and to optimize the process. When a simulation study is conducted there are some basic steps that should be followed:

- *Conduct a grid sensitivity study in both areal and vertical directions.*
- *Determine the major recovery mechanisms through mini- studies.*
- *Conduct sensitivity studies on the major uncertain reservoir data.*
- *First study the reservoir with a 1-dimensional grid, if possible, or a 2-dimensional grid system, before initiating a full 3-dimensional study.*
- *History match any field data that is available. The parameters which can be changed are the ones that have a large uncertainty associated with them, which usually include items such as the geology, relative permeability curves, and aquifer extents.*

■ 2. Well Evaluation

Proper well operation is essential to a successful pilot project. Careful evaluation of well performance is required. A brief list of the various evaluation techniques is as follows:

Pressure tests of casing integrity.

- *Back pressure tests to check for tubing leaks on pumping wells.*
- *Dynamometer surveys to check for rod fall, vapour locking and mechanical damage to bottomhole pumps.*
- *Casing deviation surveys to quantify casing movement.*
- *Casing corrosion surveys give information on both internal and external surfaces.*
- *Downhole television to inspect casing damage and obstructions.*
- *Fluid levels to calculate bottomhole pressure.*
- *Bottomhole pressure and temperature to confirm pump volumetric efficiency.*

■ 3. Surface Facilities

Surface facilities should be designed and operated to ensure that the pilot objectives are met. Commonly used evaluation techniques are:

- *Corrosion coupon tests in all potentially corrosive situations.*
- *Ultrasonic surveys to determine the thickness of pipe and vessels.*
- *Measurement of iron and magnesium concentrations in produced water to estimate corrosion rates.*
- *Annual visual inspection of vessels and generators.*

- *%Verification of test system accuracy with proving systems.*

VII. FUTURE DEVELOPMENTS IN STEAM PILOT PROJECT DESIGN

Although there are many commercially successful steam based in situ recovery projects throughout the world, there are substantial resources that remain untapped. In some instances, the technology is available for economic production at prices only slightly above today's levels of $19 US per barrel. However, the majority of the reserves await improvements in technology and/or significant prices increases. Improvements in technology can be separated into two areas as follows:

1. Incremental Improvements in Operations

In many situations the technology exists or can be readily developed to reduce costs on present day operations. Such improvements offer immediate, but modest benefits. A few of the most probable areas are:

- *Improved monitoring, identification, and control of injector-producer communications paths.*
- *Improved identification of production well plugging problems by the use of pressure transient well tests.*
- *Improvements in pumping efficiency by lowering the pump landing depths, installation of pump-off controllers and control of downhole fluid conditions.*
- *Improved energy efficiency by the use of insulated tubing, optimized surface heat exchanger networks, and steam/electricity cogeneration.*
- *Reducing oil and water treating costs through careful application of existing technology.*

2. Major Technological Advances

There are several areas that offer the possibility of substantial improvements to steam based recovery projects. Most such improvements will be related to the reservoir recovery process, as the largest opportunities presently occur here. The areas of expected major advances are:

- *Improved geological mapping will allow for a considerably better reservoir description. This will permit improved predictions of channel development and fluid movement.*
- *%Enhanced seismic techniques will enable the monitoring of channel development and fluid movement.*
- *%Development of advanced reservoir simulation programs that accurately model regions of phase changes, chemical and mineralogical interaction, stress change and associated porosity and permeability enhancements, and sand production.*
- *%Improved geotechnical models to better understand fracturing and sand production.*
- *%Development of effective methods to control fluid movement through channels and thief zones.*

VIII. ACKNOWLEDGEMENTS

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Figure 1
Active In Situ Steam Based Recovery Projects in Alberta

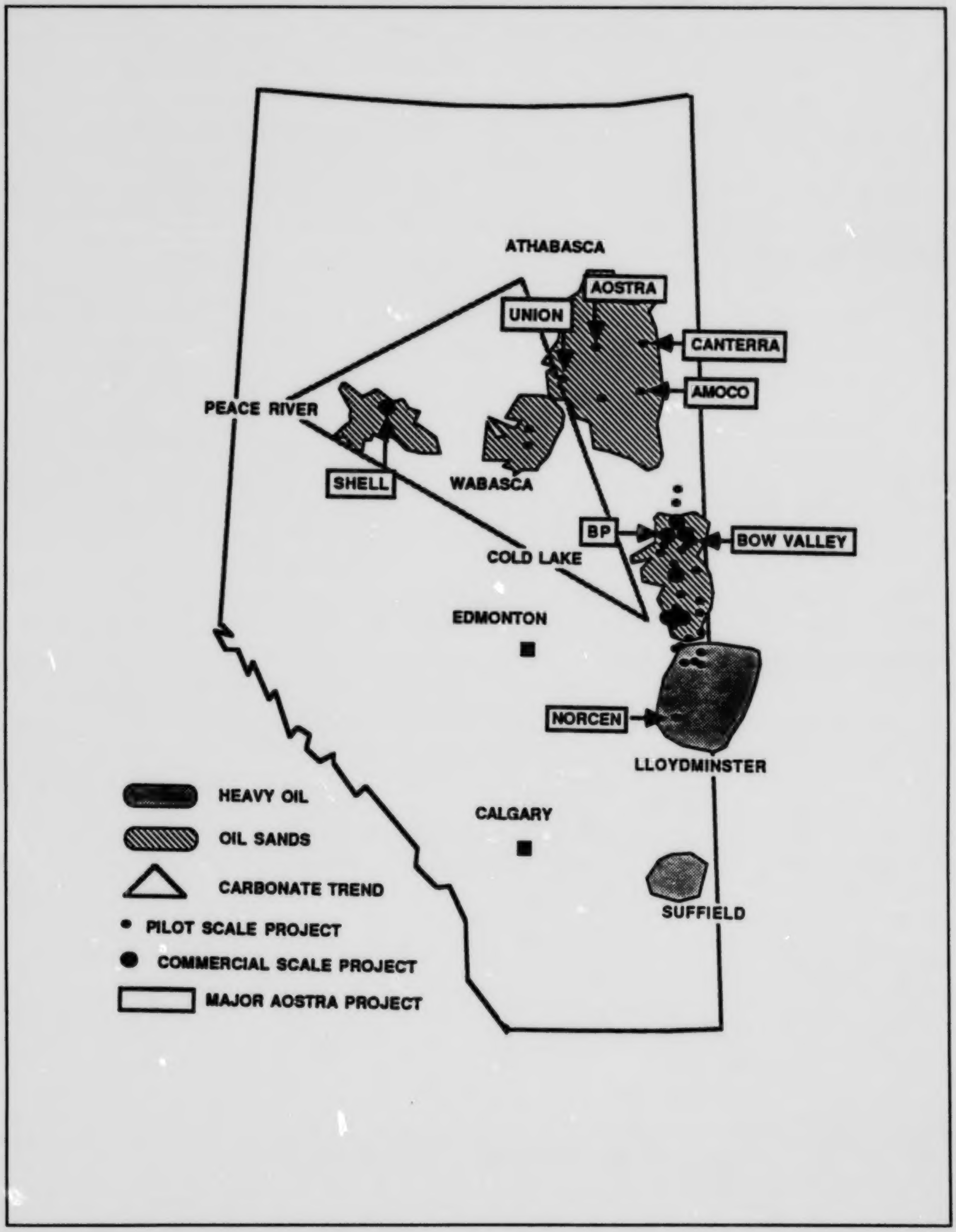

ATHABASCA
AOSTRA
UNION
CANTERRA
AMOCO
PEACE RIVER
SHELL
WABASCA
BP
BOW VALLEY
COLD LAKE
EDMONTON
NORCEN
LLOYDMINSTER
CALGARY
SUFFIELD
HEAVY OIL
OIL SANDS
CARBONATE TREND
PILOT SCALE PROJECT
COMMERCIAL SCALE PROJECT
MAJOR AOSTRA PROJECT

Figure 2
Summary of AOSTRA Steam Projects

PROJECT	AREA	FORMATION	RESERVOIR PROCESS
SHELL - PRISP	Peace River	Bullhead	pressure cycle steam drive cyclic steam stimulation
BP - MARGEURITE LAKE	Cold Lake	Clearwater	cyclic steam stimulation converted to O2 combustion
UNION - CARBONATES	Carbonates	Grosmount	cyclic steam stimulation steam drive
CANTERRA - KEARL LAKE	Athabasca	Mcmurray	fracture assisted steam flood
BOW VALLEY - ABC	Cold Lake	Clearwater	cyclic steam stimulation with CO2 and additives
AMOCO - GLISP	Athabasca	Mcmurray	fracture assisted steam drive with additives
NORCEN - BODO	Lloydminster	Mclaren	primary depletion followed by cyclic steam stimulation and steam flood

Figure 3
Development Process for a Commercial Project

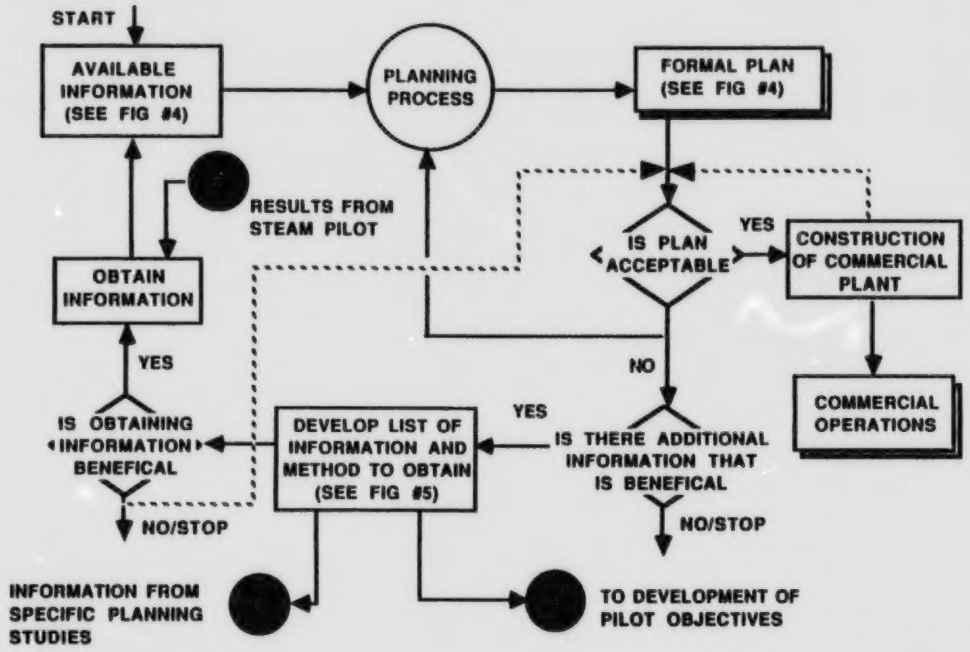

START
AVAILABLE INFORMATION (SEE FIG #4)
PLANNING PROCESS
FORMAL PLAN (SEE FIG #4)
RESULTS FROM STEAM PILOT
IS PLAN ACCEPTABLE
YES
CONSTRUCTION OF COMMERCIAL PLANT
OBTAIN INFORMATION
YES
NO
COMMERCIAL OPERATIONS
IS OBTAINING INFORMATION BENEFICAL
DEVELOP LIST OF INFORMATION AND METHOD TO OBTAIN (SEE FIG #5)
YES
IS THERE ADDITIONAL INFORMATION THAT IS BENEFICAL
NO/STOP
NO/STOP
INFORMATION FROM SPECIFIC PLANNING STUDIES
TO DEVELOPMENT OF PILOT OBJECTIVES

Figure 4
Information Sets and Planning Components for Commercial Development

SET OF AVAILABLE INFORMATION

EXPLORATION PROGRAMS
- GEOLOGY
- SEISMIC
- CORE SAMPLES
- WELL LOGS

RECOVERY PROCESSES
- LAB TESTS
- FIELD TESTS
- NUMERICAL SIMULATION
- GENERAL RECOVERY CONCEPTS

EQUIPMENT DESIGN AND CONSTRUCTION
- WELL RELATED
- SURFACE SYSTEMS

COST DATA
- CAPITAL
- OPERATING

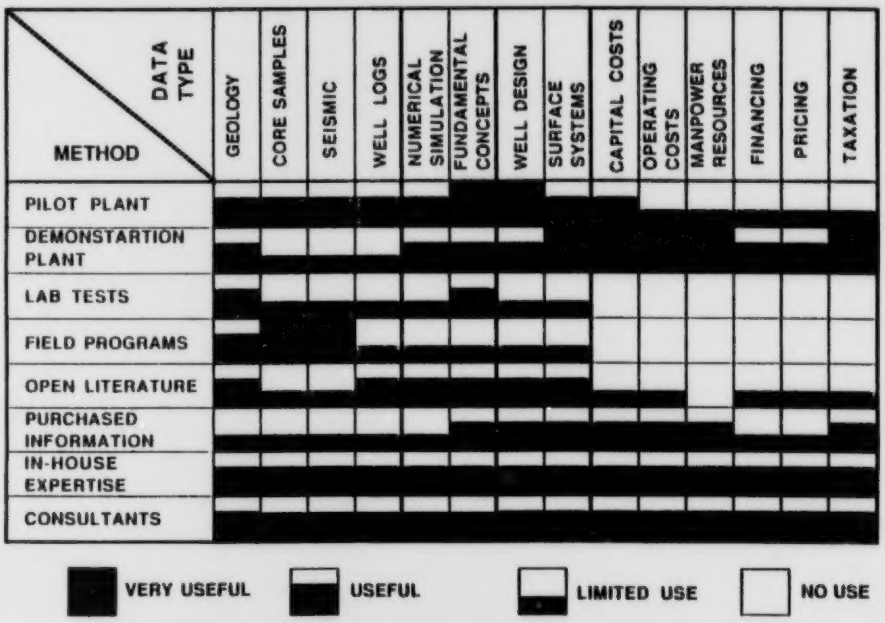
MANPOWER RESOURCES

BUSNESS FACTORS
- FINANCING
- TAXES
- PRICING/MARKETING

COMPONENTS OF A
FORMAL COMMERCIAL PLAN

- LOCATION OF THE RESERVES
- PROPERTIES OF THE RESERVES
- METHOD OF EXTRACTION
- EQUIPMENT TO BE USED
- COST OF IMPLEMENTATION
- SCHEDULE
- MANPOWER REQUIREMENTS
- SALES ARRANGEMENTS
- FINANCING
- TAXATION

Figure 5
Development of an Information List



METHOD \ DATA TYPE	GEOLOGY	CORE SAMPLES	SEISMIC	WELL LOGS	NUMERICAL SIMULATION	FUNDAMENTAL CONCEPTS	WELL DESIGN	SURFACE SYSTEMS	CAPITAL COSTS	OPERATING COSTS	MANPOWER RESOURCES	FINANCING	PRICING	TAXATION
PILOT PLANT	▆	▆	▆	▆	▆	■	■	▆	▆	▂	▂	▂	▂	▂
DEMONSTARTION PLANT	▆	▂	▂	▂	▆	▆	▆	■	■	■	■	▆	▆	■
LAB TESTS	▆	▂	▂	▂	▂	▆	▂	▂	□	□	□	□	□	□
FIELD PROGRAMS	▆	■	■	▂	▂	▂	▂	▂	□	□	□	□	□	□
OPEN LITERATURE	▆	▂	▂	▆	▆	▆	▆	▆	▂	▂	□	▂	▂	▂
PURCHASED INFORMATION	▂	▂	▂	▂	▂	▆	▆	▆	▆	▆	▆	▂	▂	▆
IN-HOUSE EXPERTISE	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆
CONSULTANTS	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆	▆

■ VERY USEFUL ▆ USEFUL ▂ LIMITED USE □ NO USE

Figure 6
Development of Objectives for a Steam Pilot

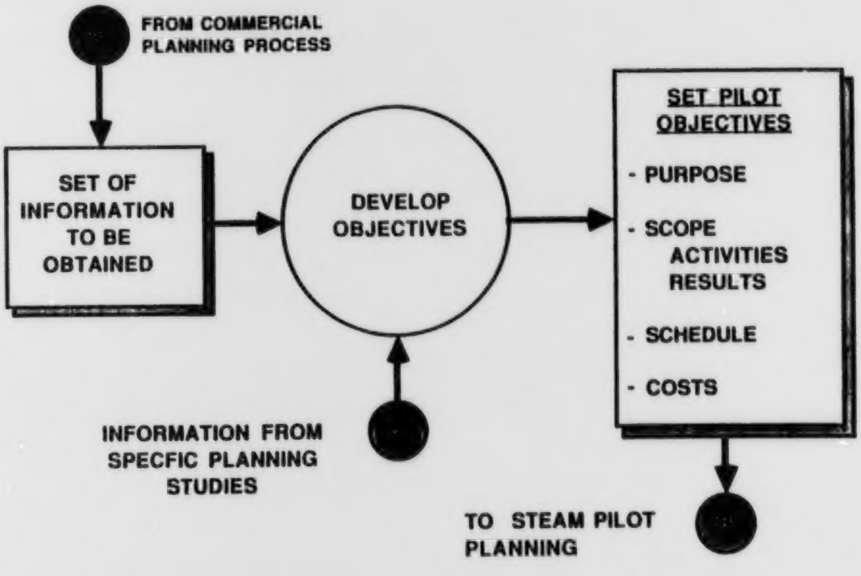

FROM COMMERCIAL PLANNING PROCESS
SET OF INFORMATION TO BE OBTAINED
DEVELOP OBJECTIVES
SET PILOT OBJECTIVES
- PURPOSE
- SCOPE
ACTIVITIES
RESULTS
- SCHEDULE
- COSTS
INFORMATION FROM SPECFIC PLANNING STUDIES
TO STEAM PILOT PLANNING

Figure 7
Planning Process for a Steam Pilot

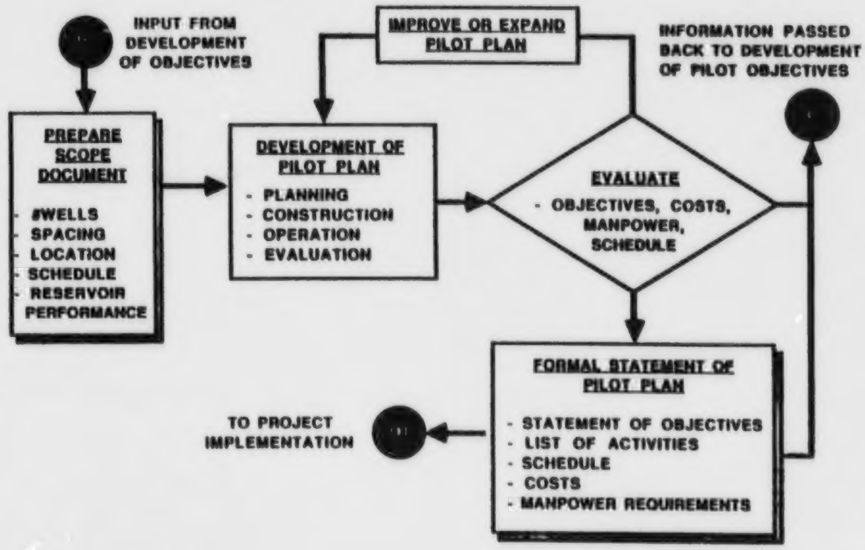

INPUT FROM DEVELOPMENT OF OBJECTIVES
IMPROVE OR EXPAND PILOT PLAN
INFORMATION PASSED BACK TO DEVELOPMENT OF PILOT OBJECTIVES
PREPARE SCOPE DOCUMENT
- #WELLS
- SPACING
- LOCATION
- SCHEDULE
- RESERVOIR PERFORMANCE
DEVELOPMENT OF PILOT PLAN
- PLANNING
- CONSTRUCTION
- OPERATION
- EVALUATION
EVALUATE
- OBJECTIVES, COSTS, MANPOWER, SCHEDULE
FORMAL STATEMENT OF PILOT PLAN
- STATEMENT OF OBJECTIVES
- LIST OF ACTIVITIES
- SCHEDULE
- COSTS
- MANPOWER REQUIREMENTS
TO PROJECT IMPLEMENTATION

Figure 8
Capacity Utilization of AOSTRA Production Treating Systems

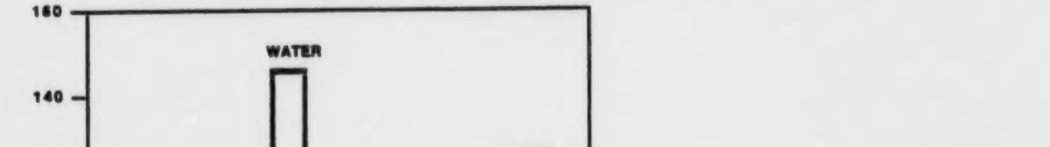


Figure 9
Typical Construction Activities

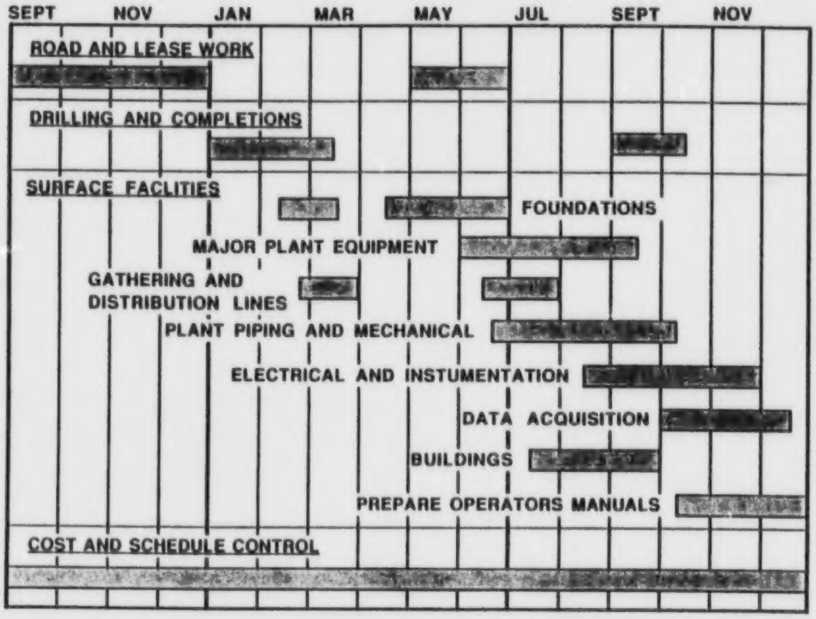
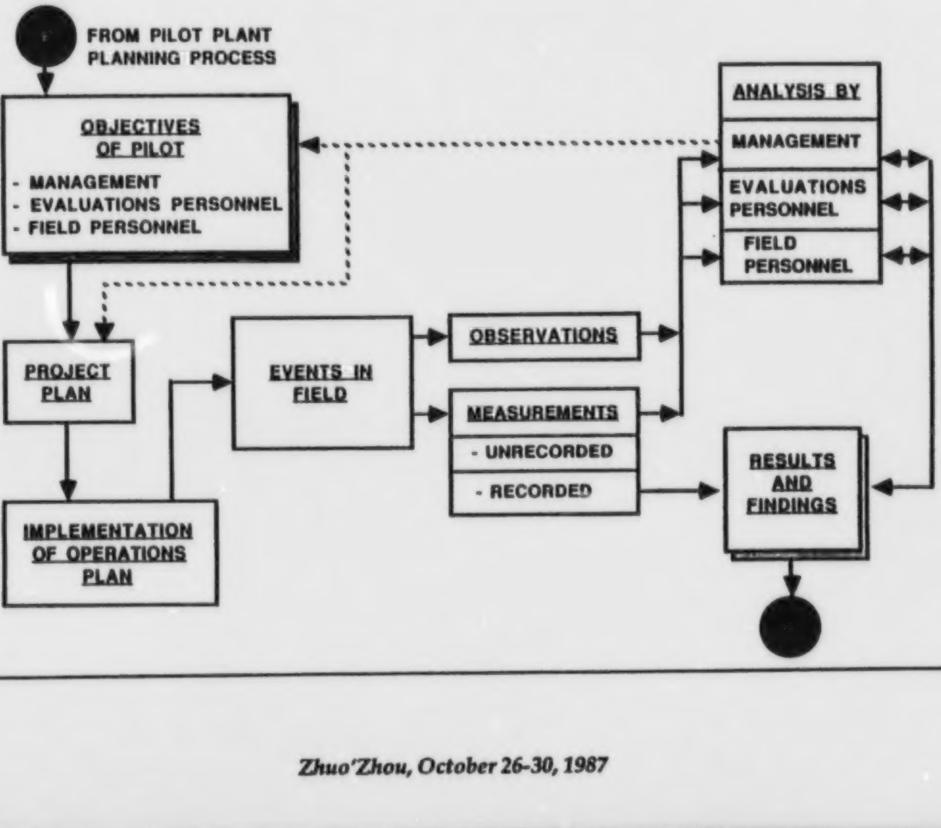


Figure 10
Evaluation Activities


FROM PILOT PLANT PLANNING PROCESS
OBJECTIVES OF PILOT
- MANAGEMENT
- EVALUATIONS PERSONNEL
- FIELD PERSONNEL
PROJECT PLAN
IMPLEMENTATION OF OPERATIONS PLAN
EVENTS IN FIELD
OBSERVATIONS
MEASUREMENTS
- UNRECORDED
- RECORDED
ANALYSIS BY
MANAGEMENT
EVALUATIONS PERSONNEL
FIELD PERSONNEL
RESULTS AND FINDINGS

31

PRODUCTION PATTERN OF THE CYCLIC STEAM PILOT AT KARAMAY NO. 9 OILFILED

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ABSTRACT

Pilot testing of cyclic steam stimulation process was conducted at Karamay No 9 Oilfield. This article presents the operating characteristics and production pattern based on statistical analysis of the production data from the pilot operations. Detailed discussion on declining rates of production and water content in produced fluids, effects of steam quality, steam injection rate and quantity in different cycles are given. For a small well spacing, the problems of inter-well communication and interference are common and serious, and undoubtedly have a significant effect on production.

INTRODUCTION

The trap type formation of the Karamay No.9 oil field belongs to a monocline reservoir which is located within a major overthrust belt and sealed by faults. Its main pay zone is a mid to fine grained sandstone with calcareous cement of the upper Jurassic (J13) Qigu formation. The reservoir is 10 to 20 meters thick. At 30 °C, viscosity of the degassed crude is 2300- 3900 mPa.s and specific gravity is 0.92 - 0.95.

In 1984, a pilot with two production patterns was developed over an area of 1.2 square kilometer. One pattern is an inverted seven spot pattern consisting of 64 wells in 14 clusters and is referred to as the 911 area. The other, referred to as 921 area, is an inverted 9 spot pattern consisting of 74 wells in 15 clusters. The 138 wells in total located within the pilot area with are spaced 100 meter between an injector and a producers, Figure 1.

By the end of 1986, the pilot had completed 296 well steaming cycles, injecting a total of 47,500 tons of steam and producing 48,200 tons of oil for a cumulative oil/steam ratio of 1.02 and oil recovery of 11.4 %. With the production capacity of 1,000 tons/day, the operation of the pilot has been quite successful.

CONDITIONS OF THE PILOT

The pilot covers 1.255 square kilometer with 3,812,000 tons of oil in place. The inverted 7 spot pattern, which encompasses 0.55 square kilometer with 1,417,000 tons of oil in place, consists of 64 wells with 14 injectors, 41 producers and 9 observation wells. The inverted 9 spot pattern extends over 0.67 square kilometer with 2,395,000 tons of oil place. It has 74 wells including 15 injectors, 54 producers and 5 observation wells.

The major oil bearing zone in the pilot area is at the upper Jurassic J1-2 about 160-240 meters beneath the surface with an average depth of about 190 meters. Reservoir and fluid characteristics are summarized in Table 1. The reservoir is moderately water-wet; its intergranular porosity ranges from 75 to 95% and pore diameter from 30 to 400 m. It is a highly permeable reservoir. The crude oil composes of 25.2% resin, 2.4% wax, 0.26% sulphur and 1.1% asphalt. Its pour point is between -16 and -23 °C.

CYCLIC STEAM STIMULATION EXPERIMENTAL CONDITIONS

Since steam was injected at Well 9-1 for the first time at the end of 1983, the pilot had undergone a one-year experimental production period. At the beginning of 1985, the pilot was formally started up. Much progress has been made during the nearly two year production period since the start-up to transform the pilot into a 1,207 tons/day production operation. Operation parameters of the cyclic steam stimulation pilot are given in Table 2.

CYCLIC STEAM STIMULATION PRODUCTION RELATIONSHIP

i) Production Declining Rate

In the CSS process, steam is injected for a period of several days followed by oil production for a period of over 200 days. Since no outside energy is provided to the formation during the production period, production rate generally peaks early in the production cycle, and drops with time as formation temperature declines, oil specific gravity and viscosity rise and relative permeability of oil decreases. The main reason for the production decline is due to the depletion of energy in the formation and the increase of oil viscosity.

Total number of production wells was 208 in 1986. The daily production excluding those from new wells, second cycle wells and improved wells are summarized in Table 3.

Although daily production of the pilot increased every month mainly due to new wells and second cycle wells, production from the first cycle wells declined exponentially with time as shown in Figure 2, with average monthly decline rate of about 16.9% or annual rate of 10.8%. From regression analysis, daily production of the first cycle wells, Q, can be related with the its cumulativ production, ΣQ, as follows,

$$Q = 600 - 0.185\ \Sigma Q$$

The regression coefficient from the above analysis is -0.9684. The intercept of the above Equation is initial daily production and the slope the average monthly decline rate. The correlation indicates that, as no measure was taken to correct the trend, the wells declined 18.5% monthly or $(1-0.185)^{12}\times100=8.6\%$ annually. Based on the monthly production data averaged over the 20 first cycle wells as given in Table 4, a similar relationship can be obtained from the regression analysis,

$$Q = 20 - 0.17\ \Sigma Q$$

The correlation coefficient is -.9502 in this case. From the above equation, monthly decline rate is 17 % and annual rate is 10.7% which agree reasonably well with the rates based on all the pilot production data.

ii) Water Content in Produced Fluids

In the CSS process, water content peaks early in production cycle , and declines gradually to a lower level. Generally, it drops to 3-5% at the end of the cycle. For the subsequent cycles, water content at the corresponding production period shows an increasing tendency with the cycles. A typical example is shown in Figure 3 for well 9124.

Generally speaking, water content declines more rapidly during flowback than pumping stage, forming a two stage declining relationship with time. This relationship is exhibited by most of the 20 first cycle wells, as shown by the plot of water/oil ratio versus the cumulative production in Figure 4.

iii) Production during Different Cycles

The pilot has so far completed the operations of 114 first cycle wells, 27 second cycle wells and 3 third cycle wells. Overall production shows a declining tendency with production cycle, as indicated by the production data in Table 5. Comparison of the data in Table 5 indicates the following effects with the increasing production cycle,

- ☐ *Production period shortened by 50 days and flowback period shortened by 10 days.*
- ☐ *Although daily production from a well changed little, production from the second cycle was 18% less than the first cycle due to shorter flowback period and production period.*
- ☐ *Overall water content increased with production cycle.*
- ☐ *Oil/steam ratio dropped and production costs increased significantly*

iv) Steam Quality

During the early experimental stage of the pilot, some of the wells were injected with very low quality steam (%). Steam quality had subsequently increased to about 70%. The production data given in Table 6 show that the effect of steam quality is large. Higher quality steam prolonged production period by about a month, increased cumulative production by 1,000 tons and raised oil/steam ratio considerably. The effect of steam quality on production declining rate is shown in Figure 5. The wells that was injected with higher quality steam usually produced at a higher initial rate and declined slower , indicating a positive impact of high steam quality on production.

v) Effect of Injected Steam Volume on Production

Injected steam volume is an important factor for the cyclic steam stimulation process. Economic study of the process indicates that steam must be injected below a certain volume for the production to be cost effective.

Steam volume was maintained between 1,000 and 2,000 tons during the first cycle injection. Based on the production data from 40 wells, cumulative production varied in direct proportion to the cumulative amount of steam injected, as shown in Figure 5. Similar relationship is observed from the scatter plot between cumulative production and the amount of steam injected per meter of reservoir in Figure 6. The wells were most productive between 80 and 110 tons of injected steam/meter of reservoir beyond which the cumulative production over one cycle dropped noticeably. With the average effective thickness of 16.4 meters over the piloting area, injection steam is best if limited to between 1300 and 1,800 tons.

Tests were conducted in the first six months of 1986 to study the effect of steam injection rate. The main objectives were to control injection pressure and minimize inter-well communication. Testing procedure involved injection of two wells from a single boiler, or three wells from two boilers, to reduce injection rate from 215 to 100-140 tons/day. Production dropped noticeably as a result. In Figure 7, cumulative production from 40 first cycle wells is plotted with steam injection rate at different oil/steam ratio. It is noticeable from the plot that when the injection rate was below 150 tons/day, cumulative production over one cycle and oil/steam ratio were lower than 2,000 tons and 1.5 respectively.

vi) The effect of Reservoir Thickness

Within the same geological formation, thicker reservoir generally contains more oil and is more favorable to oil production. To illustrate this point, 5 wells of different reservoir thicknesses located in the 911 pilot area where reservoir fluid properties are relatively superior were selected for the study. Comparison of the data in Table 7 shows a close relationship between reservoir thickness and production period, oil output/cycle and oil/steam ratio. These data indicate production from this pilot area is higher from a thicker reservoir.

vii) Inter-well Communication

The Qigu formation is a single lithological and mid to coarse grained sandstone formation with permeability higher than 10 μm^2. The highly permeable formation and the small well spacing at the pilot contribute to the interwell communication and interference. Communication is east-west trended, in the same upward tilted direction as the reservoir.

More than 35 interwell interferences have been observed since mid 1986. Some wells responded within two days of steam injection at the neighboring wells; and some like well#9020 responded with production of steam from well#9120 damaging wellhead throttling valves. Another common occurence was steam evolved from ground surface when steam was being injected as far as 200 meters away. Most of the wells responded with a drastic change in production and water content in produced fluids. Figure 8 shows the rapid rise in water content from well #9150 and #9105, and the drop in production from well #9150 when steam injection began at the neighboring wells.

It is worth mentioning that the interwell communication for most of the wells is trended consistently in the east-west direction, with the exception of a few wells due to minor faults and undeveloped fractures in the formation. According to the analysis of sedimentation angle, interwell communication is primarily in the flow direction of an ancient river. Permeability along the ancient river is higher than in other directions, which is one of main reasons for the interwell interference. Another important factor is due to the difference in vertical permeability; for some wells it can be as high as 1,000. Sometimes when steam injection pressure is higher than fracture pressure, interwell communication is possible due to formation fracture. It is, however, not always possible to control injection pressure to ensure production efficiency because of interdependent relationship of steam pressure, temperature and injection rate. The effects of interwell communication and steam breakthrough on future areal steam drive process should not be neglected, as they could become the most influential factor determining the effectiveness of the steam drive process.

CONCLUSIONS

- ☐ *Two year production practices demonstrate the technical and economic feasibility of the cyclic steam stimulation process. According to current production forecast, 20% oil recovery is possible within 3 to 4 production cycles.*

- *Production and water content decline considerably with time. Monthly production declined 18 to 20% but at a smaller rate towards the end of the production cycle.*

- *Steam quality has a significant effect on production, and should be maintained above 60%.*

- *Steam injection volume should have an upper bound; Production of the pilot is found to be most cost effective at 80 to 100 tons of steam per meter of reservoir thickness.*

- *Interwell interference due to small well spacing is prominent.*

Its effect on future areal steam drive process should be carefully evaluated. Precaution should be taken to minimize the the interwell steam channelling.

Table 1 **Reservoir and Fluid Characteristics of 9-1 Test Area**

Original Reservoir Pressure, Mpa	2.03
Original Saturation Pressure, Mpa	1.72
Reservoir Temperature(at middle part), °C	18
Average Porosity, %	32
Permeability, darcy	0.7-4
Permeability at some wells, darcy	10
Original Oil Saturation, %	66
Original Solution Gas, M^3/M^3	5
Formation Factor	1.032
Specific Gravity of Degassed Oil	0.927
Oil Gravity in Reservoir, g/cm^3	0.905
Oil Compressibility Factor, Pa^{-1}	0.1936
Viscosity of Degassed Oil @ 20 °C, MPa.s	2000-4000
Viscosity of Oil in Reservoir @ 20 °C, MPa.s	800-1100

Table 2
Cyclic Steam Stimulation Operating Parameters

Daily Injection Rate, Tons	210
Average Steaming Days/Cycle/Well	7.5
Steam Quantity/Cycle/Well, Tons	1300-1800
Steam Temperature, Degree C	270- 290
Steam Pressure, MPa	5.05-6.08
Shut-in Time, Days	3
Flowback Period, Days	10-15
Average Flowback Period, Days	18
Average Fluid Production, Tons/Day	54

Table 3
1986 May Production Data From 9th Test Area

	1985	1986			
Month	**Dec**	**March**	**June**	**Sept**	**Dec**
Monthly Oil Produced, Tons	563.7	795.8	1012.5	1405.1	1207.2
Production due to Improved wells, Tons		67.8	13.4	6.6	2.5
Production due to 2nd Cycle Wells, Tons		33.6	173.9	467.4	386.6
Production due to New Wells, Tons		299.1	611.4	819.2	757.2
Production of Old Wells, Tons	563.7	395.3	213.8	111.9	60.9
Composite Declining Rate, %		4.1	5.5		
Natural Declining Rate, %		11.2	14.9	16.4	16.9

Table 4
Monthly Production Data from 20 Wells

Month	Oil/Well,t/d	Cumulative Oil,t/d
1	19.3	19.3
2	13.7	33.0
3	11.1	44.1
4	9.5	53.6
5	8.9	62.5
6	7.6	70.1
7	6.6	76.7
8	6.0	82.7
9	5.8	88.5
10	5.2	93.7

Table 5
Production Data from Different Stages

Cycle	1	2	3
Number of Well	20	8	11
Steaming Period:			
Steaming Day	7.2	8.8	9.4
Steam Quantity, Tons	1514	1639	1788
Injection Intensity,Tons/Day Meter	15.6	13.2	14.4
Flowback Period:			
Production Day	23.7	13.8	13.6
Average Daily Production, Tons/Day	18.8	11.7	4.6
Cumulative Production, Tons	446	162	63
Composite Water Content, %	32	40	68
Pumping Period:			
Production Day	250.2	206.7	
Average Daily Production, Tons/Day	8.9	9.4	
Cumulative Production, Tons	2234	1949	
Composite Water Content, %	12.3	23.4	
Total Production Period			
Production Day	273.9	220.5	
Average Daily Production, Tons/Day	9.8	9.9	
Cumulative Production, Tons	2680	2198	
Composite Water Content, %	16.0	24.2	
Oil/Steam Ratio	1.77	1.3	

Table 6
Production Data from Different Steam Quality

Steam Quality, %	< 15	70
Number of Well	30	24
Steaming Period:		
Injected Steam Temp, C	240-270	270-290
Injected Steam Pressure, Mpa	3.55-5.07	5.07-6.08
Average Steam Quantity, Tons	1430	1555
Injection Intensity, Tons/Day Meter	2.5	15.2
Flowback Period:		
Production Day	22.2	18.1
Average Daily Production, Tons/Day	12.7	22.6
Cumulative Production, Tons	267	429
Peak Liquid Production, Tons/Day	38.1	54.3
Composite Water Content, %	43.2	31.8
Pumping Period:		
Production Day	192	232
Average Daily Production, Tons/Day	7.0	9.8
Cumulative Production, Tons	1238	2279
Peak Liquid Production, Tons/Day	23.8	54.0
Composite Water Content, %	12.7	11.7
Total Production Period:		
Production Day	220.1	250.1
Average Daily Production, Tons/Day	7.6	10.7
Cumulative Production, Tons	1654	2708
Composite Water Content, %	19.7	15.7
Oil/Steam Ratio	1.16	1.74

Table 7
Production Data from Different Formation Thickness

	*	+	#
Average Thickness, Meter	20.2	11.3	6.2
Steaming Period:			
Steam Quantity, Tons	1504	1363	1210
Injection Intensity,Tons/Day Meter	7.2	7.0	19.8
Flowback Period:			
Production Day	14.0	13.5	23.3
Average Daily Production, Tons/Day	26.2	14.1	11.0
Cumulative Production, Tons	294	170	241
Composite Water Content, %	32.9	46.9	45.5
Pumping Period:			
Production Day	272.0	220.2	128.2
Average Daily Production, Tons/Day	8.2	8.2	7.6
Cumulative Production, Tons	2251	1792	1036
Composite Water Content, %	14.1	10.2	14.4
Total Production Period			
Production Day	286.9	233.7	151.5
Cumulative Production, Tons	2545	1962	1277
Composite Water Content, %	16.8	15.3	22.7
Oil/Steam Ratio	1.69	1.44	1.06

Note: *-- From Wells 9102, 9112, 9134, 9135, 9136

+-- From Wells 9108, 9116, 9117, 9118, 9141

#-- From Wells 9119, 9126, 9127, 9128, 9130

Figure 1
Area #9 Heavy Oil Thermal Recovery Pilot at Karamay

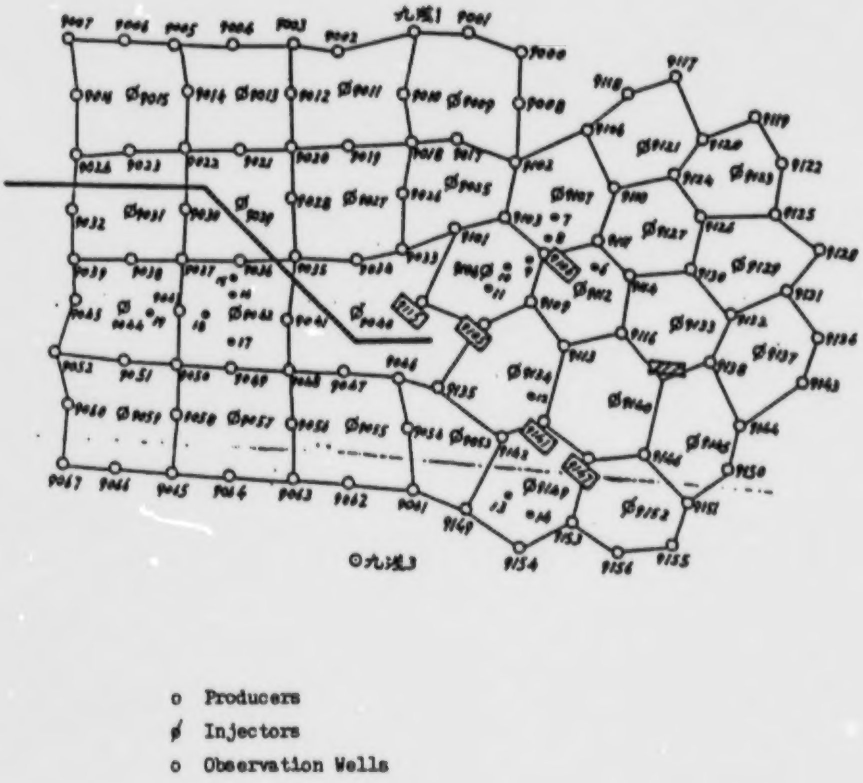

o Producers
ø Injectors
o Observation Wells

Figure 2
Daily Oil Production Declining Curves

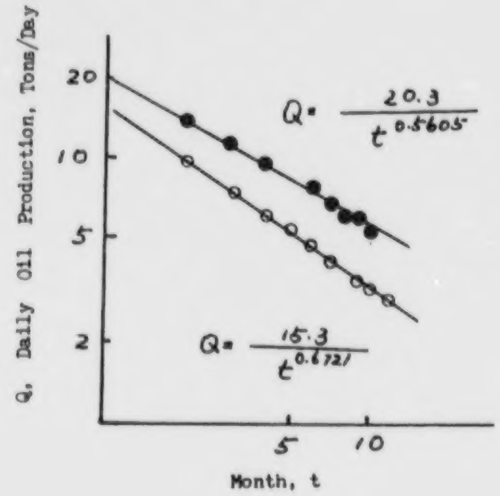


Figure 3
Well 9124 Water Content at Different Cycles

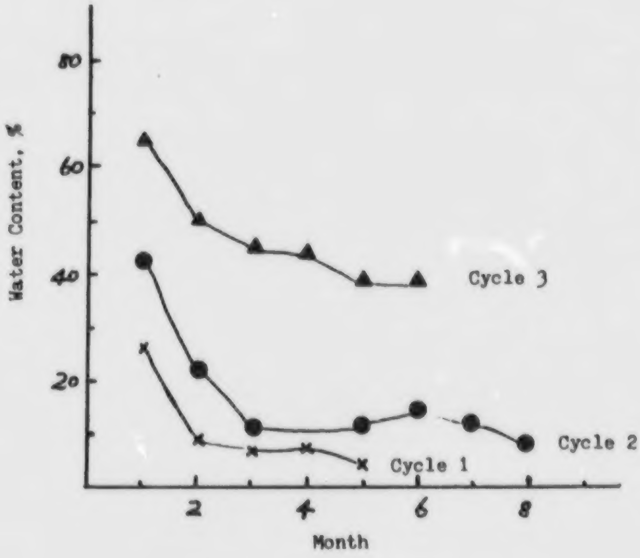


Figure 4
Water/Oil Ratio Declining Curve

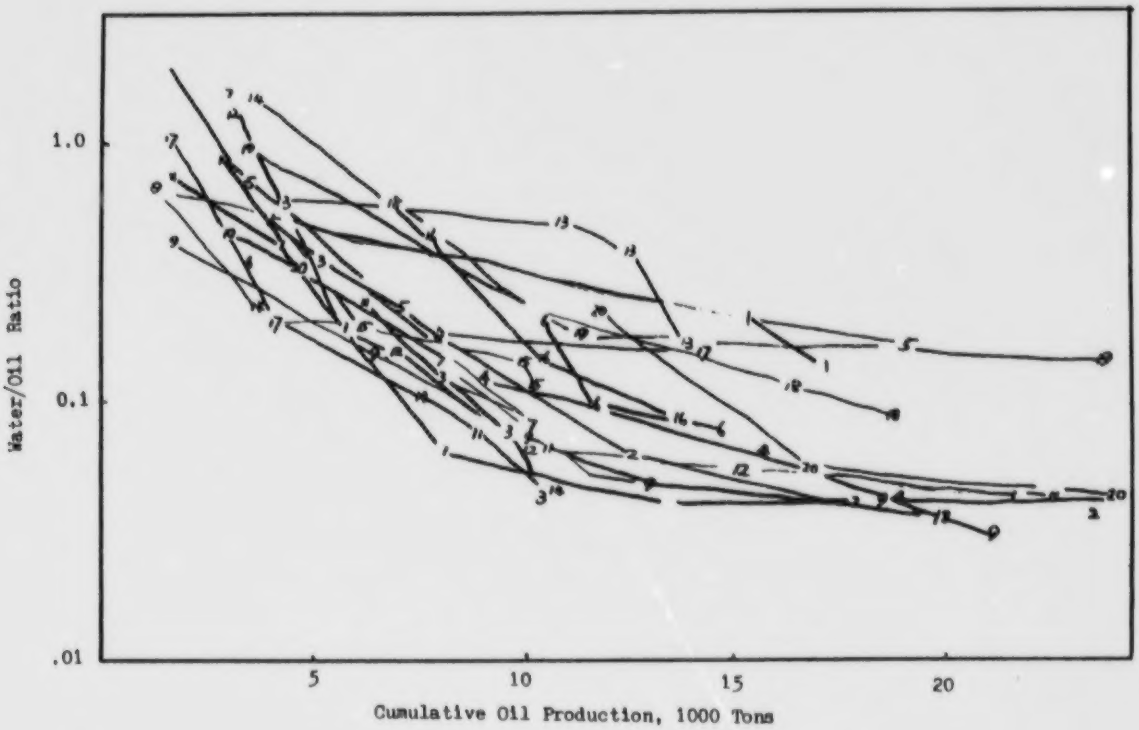


Figure 5
Oil Production at Different Steam Injection Quantity

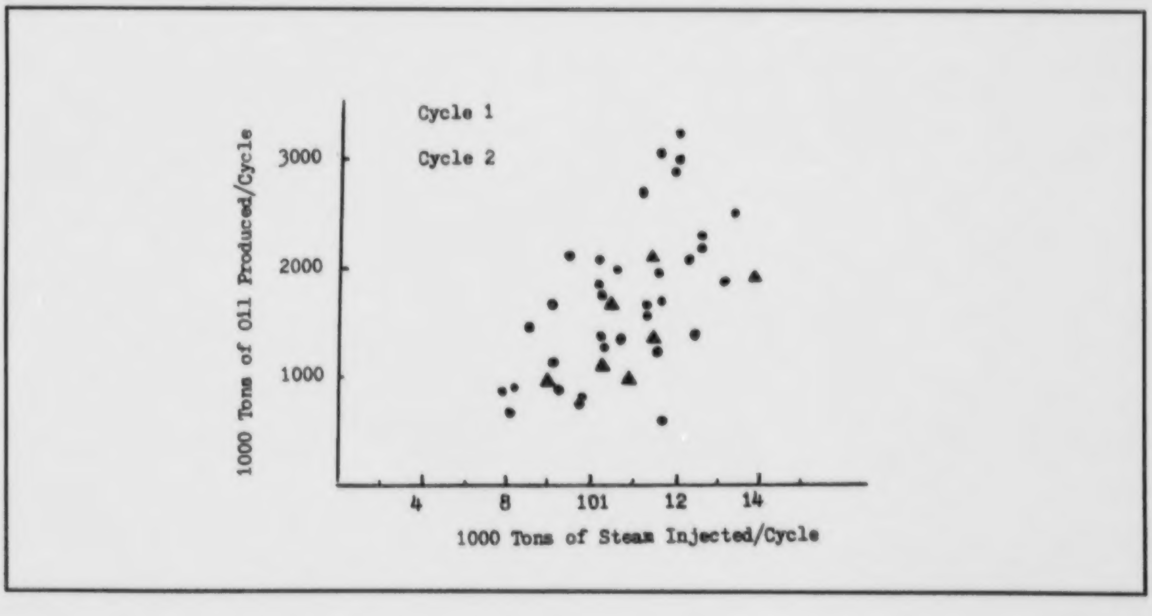


Figure 6

Effect of Steam Injection Intensity on Oil Production

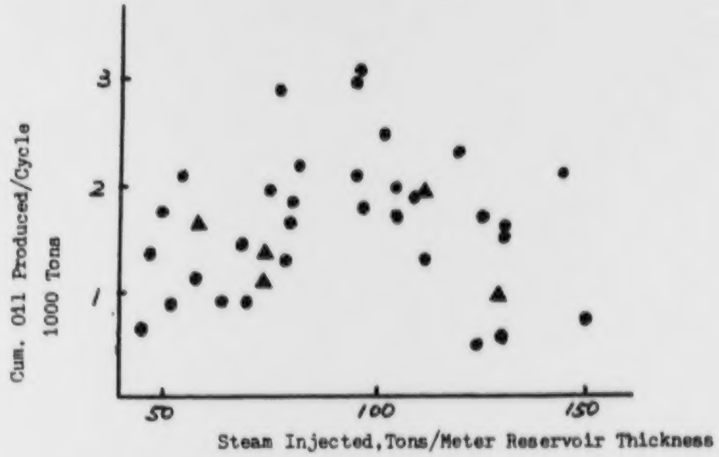


Figure 7

Oil Production Data at Different Steam Injection Rate

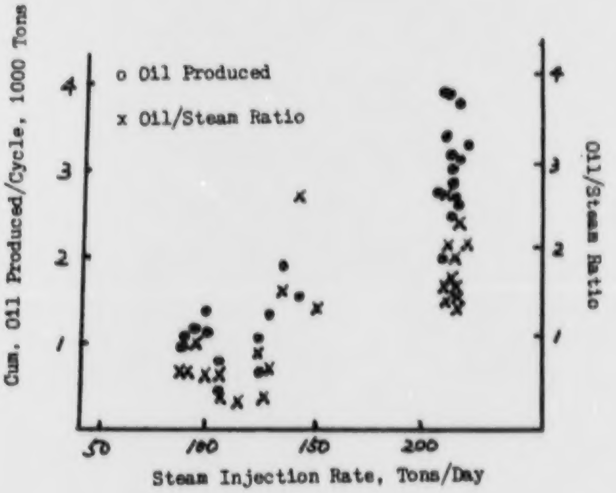


Figure 8 (a)
Well Communication at Well 9150

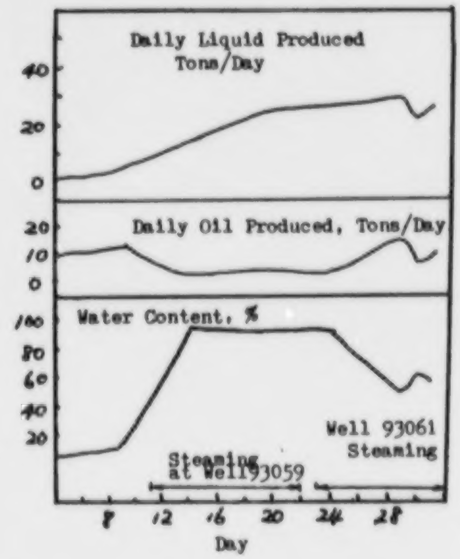
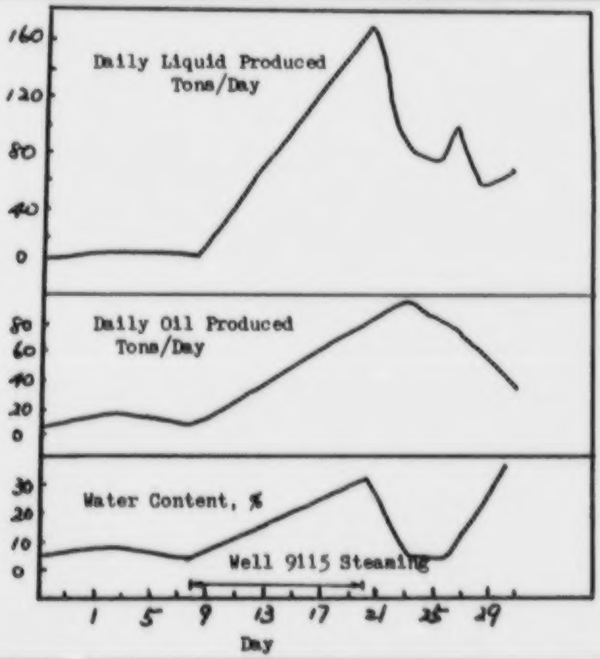


Figure 8 (b)
Interwell Interference from Well 9105



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THE FEASIBILITY STUDY OF A HEAVY OIL PROJECT

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ABSTRACT

A feasibility study of the economic prospects for the commercial development of an unexploited heavy oil deposit consists of two phases. The first includes laboratory experimental work and engineering studies, both of which have the objective of choosing the most effective recovery process and determining the economic attractiveness of it. This choice needs to be verified by carrying out the second phase which is the operation of an experiment field pilot designed to test all the assumptions used in the first phase. It is possible that a pilot may not be necessary if the operator is very experienced in heavy oil production and has a detailed knowledge of a reservoir similar to the one being studied. Generally, however, it is prudent to check the simulations and laboratory work with data from a field experiment. If the pilot performs satisfactorily, the field installation can be expanded in a step-wise fashion to exploit the whole reservoir. When the pilot performance is significantly different from that predicted, the new information should be incorporated into a re-examination of the predictions and conclusions from the Phase 1 evaluation. If the new studies incorporating actual field data predict a suitable economic return, then a commercial project could go ahead with a high degree of confidence. This paper will discuss very briefly the activities involved in Phase 1 and will give ideas for the design and expansion of a Phase 2 single well pilot.

PHASE 1

The Phase 1 activities include laboratory work and other studies in the area of geology, reservoir engineering, drilling and well completions, facilities, and economic analysis.

■ Geological Studies

Geological work provides the basis for predictions that a newly discovered reservoir has commercial potential. The objective of the geological investigation is to define the limits of, and characterize, the heavy oil occurrence. Much of the data for doing this comes from (a) cores and cuttings from drill holes which have penetrated the reservoir and (b) well logs over the zones of interest. Also, if type sections of the reservoir are present in nearby outcrops, these can be examined to add to the information gleaned from drilled wells.

It is understood that there will not be a major interest in developing a deposit until several wells have been drilled into it to demonstrate that there is sufficient oil-in-place to warrant the work involved in investigating possible recovery techniques. However, after the presence of substantial volumes of oil have been confirmed, work can go ahead to define the properties and characteristics of the reservoir which are of importance for the follow-up reservoir engineering studies. For example, porosity and permeability of the rock should be measured or calculated as well as the percentage of connate water in the pore spaces. Gas and/or water zones, if present, should be mapped and incorporated into charts of the reservoir geometry. The reservoir rock itself should be characterized in terms of mineral content, grain size distribution, etc.

■ Reservoir Engineering

The major reservoir engineering studies are predictions of reservoir response to be expected from the application of different recovery processes. The input to these models includes the geological parameters, data on the crude's viscosity-temperature relationships, data on heat conduction and convection, experimental data from laboratory displacement tests, etc. The output from numerical simulations includes predictions of required injection volumes, composition and amounts of produced fluids, percentage recovery from the reservoir, etc.

Different processes should be studied to permit comparison of the expected performance from each (eg: steam injection, combustion, etc.) and to provide direction for choosing the most attractive technique for exploiting the heavy oil. The predictions should also contain a recommendation for a proposed spacing pattern (both distance between wells and type of pattern - eg. 5 spot, 7 spot, line drive, etc.) for a commercial development and should provide an indication of expected movement of the heat front in the reservoir as well as estimates of the efficiency of the process (eg: steam/oil ratio, etc.) and the percentage recovery form the reservoir.

The paper by Dr. Anthony Au[1], presented at this symposium, is an example of the type of reservoir study which can be useful in the evaluation of different alternatives for stimulating a heavy oil reservoir.

■ Drilling and Completion of Wells

Little will be written on this topic as other papers[2,3] in this symposium are dealing with it. It is worth noting, however, that one must be sure to examine each of the drilling alternatives, including vertical, slant, and horizontal wells. The best choice will depend upon a number of factors, such as well spacing in the reservoir, relative costs of drilling, ground surface conditions, heat losses, and well pumping difficulties.

Well completions are covered in a paper by M. E. McCormack[4].

■ Preliminary Facilities Design

A preliminary design of facilities for a large scale commercial project must be prepared in order to estimate costs and to serve as the basis for the detailed design if it is decided to proceed with construction. Other papers at this symposium are covering portions of the facilities' concerns including: production systems[5] and surface facilities design[6], steam systems[7], and techniques for handling produced water. It is important when considering heavy oil development to realize that the facilities related to the injection into, and production from, oil wells are not the only major components. Equally important is the upgrading installation. The design and cost of this equipment must be incorporated into the field system as heavy oil cannot be pipelined at ambiant temperatures away from the main gathering station and usually must be refined to a synthetic crude or to petroleum products for transportation to market. There is a paper[9] being presented at this symposium which discusses the selection of an appropriate upgrading process.

■ Economic Evaluation

Finally, all of the above preliminary design and cost estimation work is brought together in an economic evaluation of the projected heavy oil recovery project. The input and techniques for this work are covered in another paper[10] at this symposium.

The purpose of economic analyses is to determine whether or not there are attractive prospects for future commercial operations. If the conclusions show that a large scale development could yield a satisfactory return on money invested, then before proceeding one must carefully consider the accuracy of the input assumptions. Most of these would be quite realistic as they would be based upon data from similar designs, studies and projects. The major area of doubt, however, will be the question of actual reservoir performance compared to that predicted by the numerical and physical simulations carried out by the reservoir engineers and their colleagues. The best way of resolving much of this uncertainty is by conducting a pilot test to gather data on how the chosen stimulation technique actually will perform in the field.

PHASE 2

Conducting a field experimental pilot is the usual second phase of an evaluation of the commercial prospects for a heavy oil reservoir. It is not necessary to expend large amounts of money for this test as the initial pilot need only consist of a single well project which is capable of being expanded into an ever larger producing operation.

The following discussions is a specific example of a progression of pilots which can test the steam injection process in an undeveloped heavy oil reservoir. The experiment begins small and progresses to a multi-well operation which has the potential for further expansion to a large scale commercial project.

Steam stimulation (huff and puff) is the usual process of primary interest in the early recovery experiments for a heavy oil reservoir. In this process, each well initially acts independently of any other and its performance is governed by the reservoir in its immediate vicinity. Unheated oil in the formation surrounding an operating well tends to isolate it from other wells or parts of the reservoir. Given the fact that each well's performance is initially little influenced by other wells, it is acceptable that a field pilot begin with the stimulation of only one well which should be located so that it will test reservoirs of average quality. It would also be desirable to keep the ancilliary facilities simple in order to minimize costs until there has been encouraging well performance which would initiate the testing of a more complex multi-well project.

The single operating well should incorporate all the components of the average well being considered in the plans for the large scale commercial project. These would include: drilling technique, completion technique, tubulars program, wellhead components, injection and pumping configurations, etc.

As the main purpose of the early pilot work is to gather data on well and reservoir performance, there is little need to evaluate commercial scale facilities for steam injection and production handling. These can be very simple and need not be prototypes which would be suitable for a large project. The following items should be sufficient for injecting steam into, and handling the resultant production from, a single well: an office trailer, a portable steam generator and water treatment unit (26 GJ per hour or approximately 25 million BTU's per hour), a production storage tank (750 or 1000 barrels), and two 400 barrel storage tanks (one for raw feed water and the other for softener backwash water). With this minimum set-up, it will be necessary to transport production away from the location by truck to an installation which has an oil/water separation capability. It may also be necessary to use a tank truck to carry raw water to the lease and possibly to remove backwash water to a disposal area. Finally, it would be most desirable to have both a natural gas supply for the steam generator and also power for the various electrical components.

It is suggested that for the single well test there be three observation wells each about 25 meters from the central location and spaced equally around it. These wells should be fitted with (a) a bubble tube to measure downhole pressure and (b) an in-hole stationery multi-point thermocouple string to supply data for temperature profiles across the reservoir interval. A well's thermocouple bundle could typically include 16 temperature measuring points with 10 spaced 1 or 2 meters apart across the oil column and the remainder spotted at appropriate locations above and below the reservoir. The data from these wells should give an indication of reservoir pressure communication within the oil zone and also the location, both areally and vertically, of the intervals being heated as a result of steam injection into the operating well. More details on a design for a single well facility are included in an appended copy of Appendix 2 of a report prepared in 1986 by Nimarec Engineering Ltd. for a research program which is jointly funded by the province of Saskatchewan and by Energy, Mines and Resources, Canada. The Saskatchewan Department of Energy and Mines has graciously given permission for Appendix 2 of the report to be attached to this paper.

The single well test should be operated for approximately 1 year (three or four huff and puff cycles) to gather information on well productivity and heat movement within and outside the reservoir. Consideration should then be given to drilling three additional injector/producer wells to expand the pilot to permit more meaningful interpretations of the probably overall reservoir performance. These additional wells may be drilled in a cluster (ie: deviated from a central location) if it is desired to test this alternative as a future development possibility. The bottomhole locations of the wells should be positioned so that they will form part of any expansion to a commercial spacing seven-spot pattern and also should provide data for at least a partial analysis of the inter-well communication trends. The new wells should provide more meaningful data on "average well performance" than is available from a single well. This three-well expansion would require additions to the injection and production equipment and, at this stage, it would be wise to look to the future and install equipment which would be suitable for handling at least seven injection/production wells. Installation of a larger steam generator as well as an oil/water separator, additional tankage, water disposal facilities, etc., would be required.

Operation of the pilot, including stimulation of the four wells, should continue until there are sufficient data to make a decision on expansion possibilities. It may be desirable to drill another three wells to complete the seven spot for an evaluation of a commercial spacing pattern. Alternatively, if results from operation of the four wells indicate that the initial testing was too wide, then additional wells could be infill locations.

Subsequent changes to the facilities and operations will be dependent upon pilot performance. There are so many possibilities that discussion of them is beyond the scope of this paper. There is attached, however, for those interested, a short, unpublished paper by Nimarec Engineering Ltd. entitled "Evaluation of an Enhanced Recovery Process for a Heavy Oil Reservoir" which deals with a philosophy for expanding a pilot test from a single well. The key sentences in the paper may be:

> *The results from field operations should be subjected to a very careful and ongoing detailed examination and analysis of each well's performance. The aim of these studies would be to determine average well performance. A logical succession of pilot wells should*

provide for the progression towards a more and more meaningful measure of average well performance which can then be incorporated into economic studies.

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- 10. Werth, F. J., Economic Evaluation of a Heavy Oil Recovery Project, (AOSTRA) presented at the 1987 China-Canada Heavy Oil Symposium.

ATTACHMENT 1

APPENDIX 2

DESIGN PARAMETERS AND DESCRIPTIONS OF COMPONENTS FOR A SINGLE WELL PILOT - STAGE I

PRODUCTION/INJECTION WELL

The well design presented in Figure 2 is based on that of wells from large projects drilled into Mannville sand reservoirs in Alberta and Saskatchewan. The design is the result of cost and performance optimization over several years of development.

The proposed well would be drilled vertically into the Mannville sand and would be cased with high strength 'roduction casing (L-80) complete with buttress threads designed to cope with the axial forces induced by the heating and cooling involved in steam work. Thermal cement with 40% silica flour would be used to maintain cement integrity at high temperatures. The production casing would be landed one-third of the way through the target reservoir to minimize gas production and steam blowback. A wire wrapped screen to control sand production is shown in the well diagram but other screens are available or are being developed and the alternatives should be considered to make the best choice for the particular reservoir being tested.

The study well is equipped with a 6.4 mm (1/4") continuous, stainless steel bubble tube, strapped to the 89 mm (3.5") tubing. When fed with a continuous, low volume of compressed gas, this tubing acts as an accurate, simple measure of bottomhole pressure. To take a reading, the supply gas is shut off, the tubing pressure allowed to stabilize, andggauges are read on surface. With an adjustment for the effect of the gas column, a bottomhole pressure is obtained.

Three temperature/pressure observation wells (see Figure 3) are located near the injection/production well to provide information on the reservoir's characteristics and the behavior of steam in the reservoir. The wells are equipped with thermocouples to measure downhole temperatures and with bubble tubes to provide bottomhole pressure data.

The stationary, multi-point thermocouple strings available today are more expensive than a single point, traversing set-up but their reliability and ease of operation make them the preferred equipment. A well's thermocouple bundle could typically be comprised of 10 temperature measuring points at 1.5 m spacing through the target reservoir with an additional three points both above and below the interval at 3 m spacing. In addition, surface readout equipment for the three 16-point thermocouple strings would be required to complete the installation.

The bubble tube system consists of 6.4 mm continuous stainless steel tubing strapped to tubing carrying the thermocouple bundle. The bubble tube would be run to the perforations. Figure 4 is a schematic of the bottomhole pressure measurement system.

STEAM GENERATION

When approaching a new reservoir with the intention of testing a steam EOR technique, it is difficult to estimate beforehand the likely injection rates and pressures. These rates and pressures are important not only in determining the overall pilot operating strategy but, in addition, they are required for the design and specifications of the steam generating and distribution equipment.

Steam generators are commonly available with capacities of 26 GJ/hr. (25 mm BTU/hr.) and 52 GJ/hr. (50 mm BTU/hr.). For the single well test, it is felt that the smaller unit would be suitable. Figure 5 is a flow sheet for the steam system. It has sufficient capacity (about 270 m/day or 1700 bpd) for the test and would be somewhat smaller and hence more portable. In addition, with the 3 to 1 turndown ratio (normal for single pass generators) the minimum steaming rate, without venting, would be about 3.7 m^3/hr. This minimum rate could be significant in a situation where there was a well injectivity problem.

The injectivity associated with a new well may or may not require that a high pressure steam generator be used. Steam generators are divided into two pressure ratings, above and below 14,000 kPa (2000 psia), with the price rising considerably for the higher pressure models. It is felt that it would be appropriate for a Saskatchewan operation that the rental unit to be used for the initial operations be capable of operating in the higher pressure range. During the early pilot work, it would be possible to gather rate and pressure date which would determine whether a high pressure unit should be specified for the subsequent purchase (assuming good pilot performance and expanding operations) of a "permanent" generator. The new unit would in all likelihood be a 52 GJ/hr. generator, which has "economies of scale" and which would be well suited to a larger steaming operation involving up to seven wells.

The portable rental steam generator packages include water treatment equipment as well as an electrical generator. However, as the pumpjack driver and thermocouple equipment will require power after the steam generator has been released, it would be best to supply outside power to the site. Figure 5 indicates the components and capacities of the rental steam generation facility.

A 26 GJ/hr (25 mm BTU/hr.) rental steam generator will require about 20 $10^3 m^3$/day (700 mcfd) of natural gas. If propane is used, the requirement will be about 25,000 litres per day.

At a maximum steam generator output of 300 m^3/day of water as 80%, 10,000 kPa steam, a cycle would take about 20 days to complete. This total volume of 6000 m^3 is calculated from the assumption of 400 m per meter of pay for a 15 meter thick reservoir. The projected two steam cycles for year one would result in a gas consumption of 800 10m.

POWER SUPPLY

A single well test would require power for the steam generator pump and blower motors, pumpjack motor, ground water pump(s), bubble tube gas compressor, thermocouple system, electric heat tracing and general lighting. This demand could be met by portable generators if required (and in fact portable steam generators do come equipped with electrical generators) but the reliability of electricity from a provincial grid system would be preferred for the pilot and would be required for a larger project.

WATER SUPPLY

The water requirement for a 26 GJ/hr. (25 mm BTU/hr.) steam generator running at maximum rates is about 300 m^3/day including filter and softener backwash volumes. If ground water wells near the lease can meet the demand, this is the least expensive supply and often has the additional advantage of being of better quality than surface water. If sufficient ground water is not available, surface water sources will have to be used.

A raw water surge tank will be required to supply backwash water for the filters and softeners as well as serve as a reservoir to supply the steam generator. In addition, a backwash water tank will be necessary for the storage of water awaiting disposal. Two 64 m^3 (400 bbl) tanVs should be suitable. It is estimated that there would be about 30 m^3/day of backwash water which would require disposal.

BOTTOMHOLE PRESSURE MEASUREMENT SYSTEM

This system (Figure 4) facilitates the gathering of bottomhole pressures from the production/injection well and the three observation wells. One 6.4 mm (1/4 inch), continuous stainless steel tubing is run into each well strapped to a tubing string. A small natural gas compressor is used to supply gas to the four wells at pressures exceeding the bottomhole steam injection pressure. Valves on surface regulate the gas flow down these bubble tubes at low constant rates to keep the tubes from becoming plugged with heavy oil or possibly sand. When a bottomhole pressure reading is required, the controlling valve is closed, the pressure in the tube is allowed to stabilize and the pressure at surface is read on a gauge. The effect of the gas column is calculated and an accurate pressure, equivalent to a bottomhole reading, can be obtained.

The bottomhole pressure facility is used to: accurately measure injection pressures, conduct pressure fall-off surveys, and observe pressure responses at observation wells, all of which data aid in the analysis of reservoir performance.

PRODUCTION TREATMENT AND MEASUREMENT

The single well test can be efficiently carried out with a minimum of production equipment as illustrated in Figure 5. One or possibly two atmospheric tanks should be sufficient to handle the well's production. The tanks should be insulated and come equipped with gas fire-tubes. The tank(s) are sized to contain two to three days of production from the well at its highest producing rate. For our study project, a tank capacity of 120 m^3 (750 bbls) should suffice.

A simple, yet accurate method, of determining production volumes involves taking periodic samples from the well, determining the oil, water, and sand percentages and applying these to hand gauged volumes from the production tank. If the produced fluids separate readily in the tank, the cuts can be checked, but often the emulsions produced in steam operations require more sophisticated treatment than tank separation alone. A side benefit of the single well test is that it will provide information on the water separation facilities which will be required for a further expansion of the pilot.

PIPING

Expected pressures for injection in Saskatchewan reservoirs (10,000 kPa or more) indicate that schedule 80 pipe will be required for the 3-inch steam injection line. Production piping that is not subject to high pressure steam can use schedule 40 pipe.

Heat tracing to prevent above ground pipe freeze-up in the winter months should be installed and for the limited amount of piping required for a single well test, electric heat tracing is most practical. The above ground production and steam piping should be insulated with calcium silicate insulation with cladding, a set-up that can withstand the abuse it always receives in well traveled areas.

DATA GATHERING

The operator of a steam project must gather sufficient data on an ongoing basis to be able to intelligently interpret the performance of the pilot wit a view to determining the appropriateness, or otherwise, of the proposed reservoir operations plan. While it is necessary that critical information not be missed, it is also unwise to spend money obtaining data of little practical use. A minimum list of information which must be gathered and recorded for later manipulation and study includes daily readings of:

1. Injected steam volume
2. Steam quality
3. Wellhead tubing pressure from the injection/production well
4. Bottomhole pressure from the injection/production well
5. Temperature surveys from observation wells (16 pts. X 3 wells)
6. Bottomhole pressures from injection/production well and from observation wells
7. Produced volumes of water, oil, sand, and gas
8. Wellhead temperature
9. Annulus pressure
10. Hours on production
11. Hours on injection

These data can easily and inexpensively be gathered and recorded by field personnel. The data can be sent to the engineering office in a number of ways, perhaps the simplest being via a phone link between personal computers.

Additional data pertaining to steam generator operations and/or daily lease activity should be recorded on summary sheets by the operators and stored for future reference.

LAB/OFFICE TRAILER

A small trailer is required to provide limited office space, to house the observation well thermocouple readout panel, to provide space for production sample analyses, and to take care of the storage of items used in day-to-day operations.

ROAD AND GRAVEL

Although a minimum of roadway and site preparation is required for a single well test, sufficient work should be done to allow operations to continue during rainy periods and spring break-up. The site should be located the minimum practical distance from maintained government roads.

SASKATCHEWAN ENERGY AND MINES
EOR PILOT PROJECT PROGRAM
SINGLE WELL TEST
BOTTOMHOLE PRESSURE MEASUREMENT SYSTEM

Flow Stream Number	Fluid	Flow Rate Average	Pressure kPa	Temperature °C
1	Natural gas	800 m³/day	1,000	20
2	Natural gas	200 m³/day	10,000	40

SASKATCHEWAN ENERGY AND MINES
EOR PILOT PROJECT PROGRAM
SINGLE WELL TEST WITH RENTAL STEAM GENERATOR
STEAMING AND PRODUCTION PROCESS

Flow Stream Number	Fluid	Flow Rate Average	Pressure kPa	Temperature °C
1	Raw water	300 m³/day	150	10
2	Fuel gas	20 m³/day	350	10
3	Softener backwash	50 m³/day	200	10
4	Steam (80% quality)	250 m³/day*	14000	367
5	Oil/water	38 m³/day**	700	150

* Assumes no injectivity problems.

** Production based on Pike's Peak results.

Figure 1
Equipment Layout Drawing

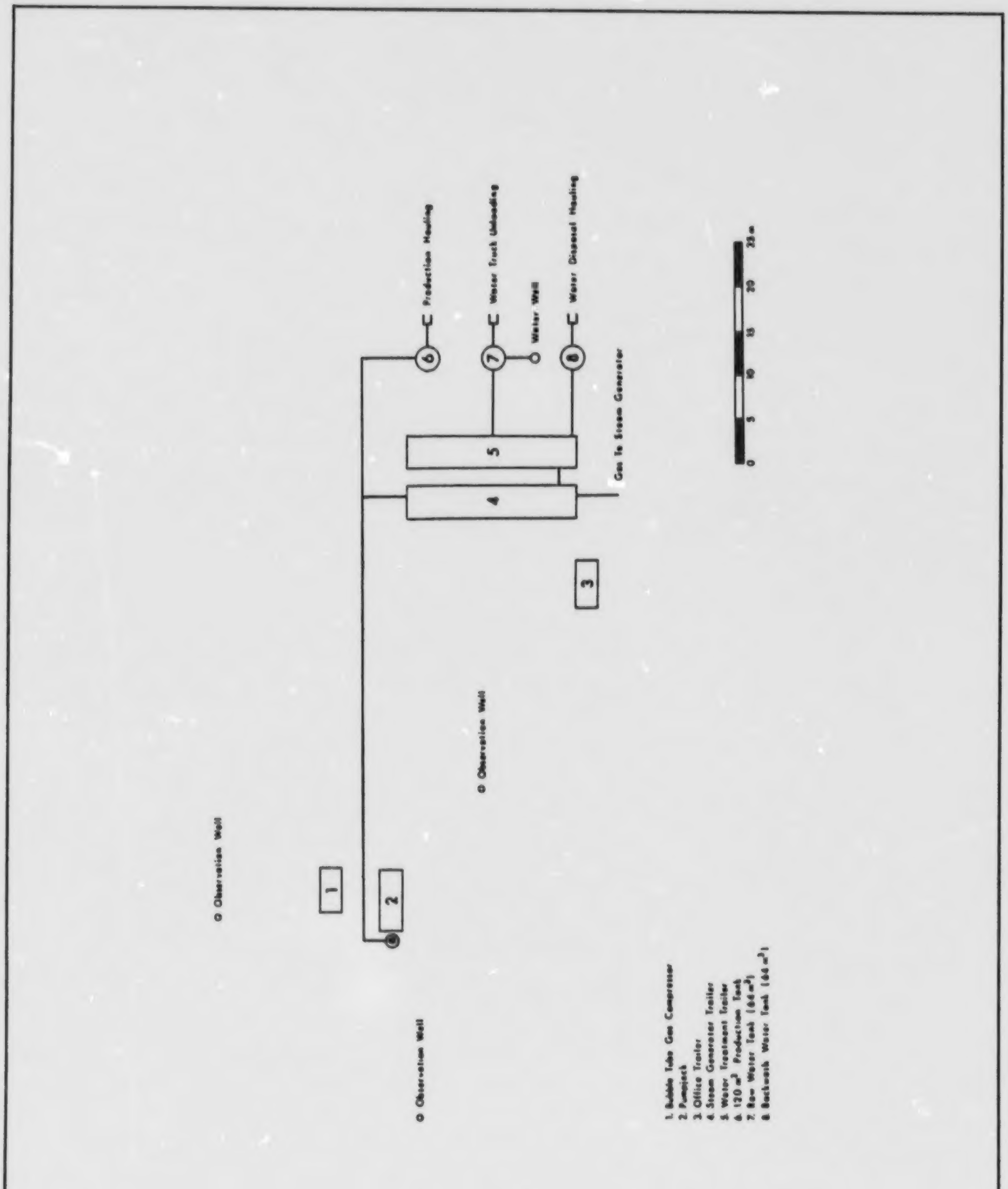

Observation Well
1
2
Observation Well
Observation Well
3
4
5
6
7
8
Production Hauling
Water Truck Unloading
Water Well
Water Disposal Hauling
Gas To Steam Generator
0
5
10
15
20
25 m
1. Bubble Tube Gas Compressor
2. Pumpjack
3. Office Trailer
4. Steam Generator Trailer
5. Water Treatment Trailer
6. 120 m³ Production Tank
7. Raw Water Tank (64 m³)
8. Backwash Water Tank (64 m³)

Figure 2
Typical Steam Injection/Production Well Completion

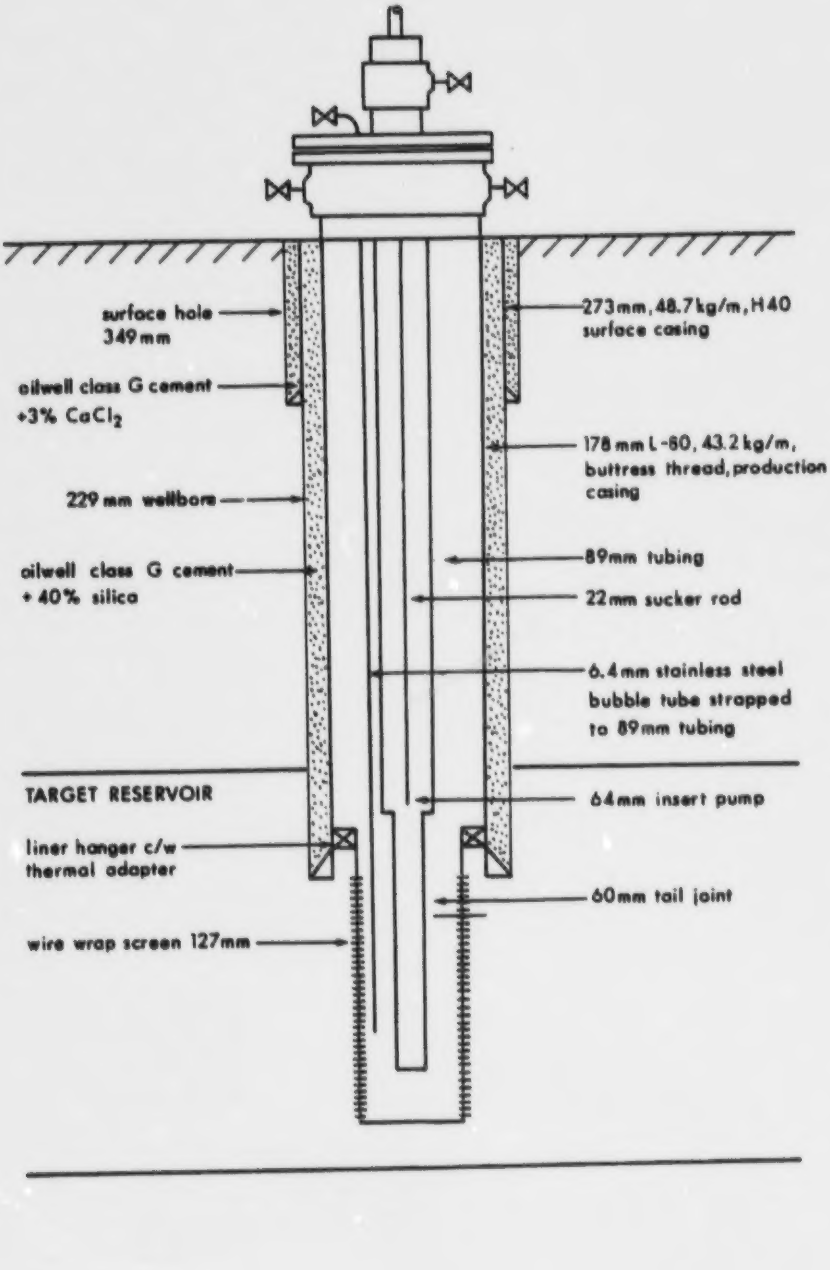

surface hole 349mm
oilwell class G cement +3% $CaCl_2$
229 mm wellbore
oilwell class G cement + 40% silica
TARGET RESERVOIR
liner hanger c/w thermal adapter
wire wrap screen 127mm
273mm, 48.7kg/m, H40 surface casing
178 mm L-80, 43.2 kg/m, buttress thread, production casing
89mm tubing
22mm sucker rod
6.4mm stainless steel bubble tube strapped to 89mm tubing
64mm insert pump
60mm tail joint

Figure 3
Typical Observation Well Completion

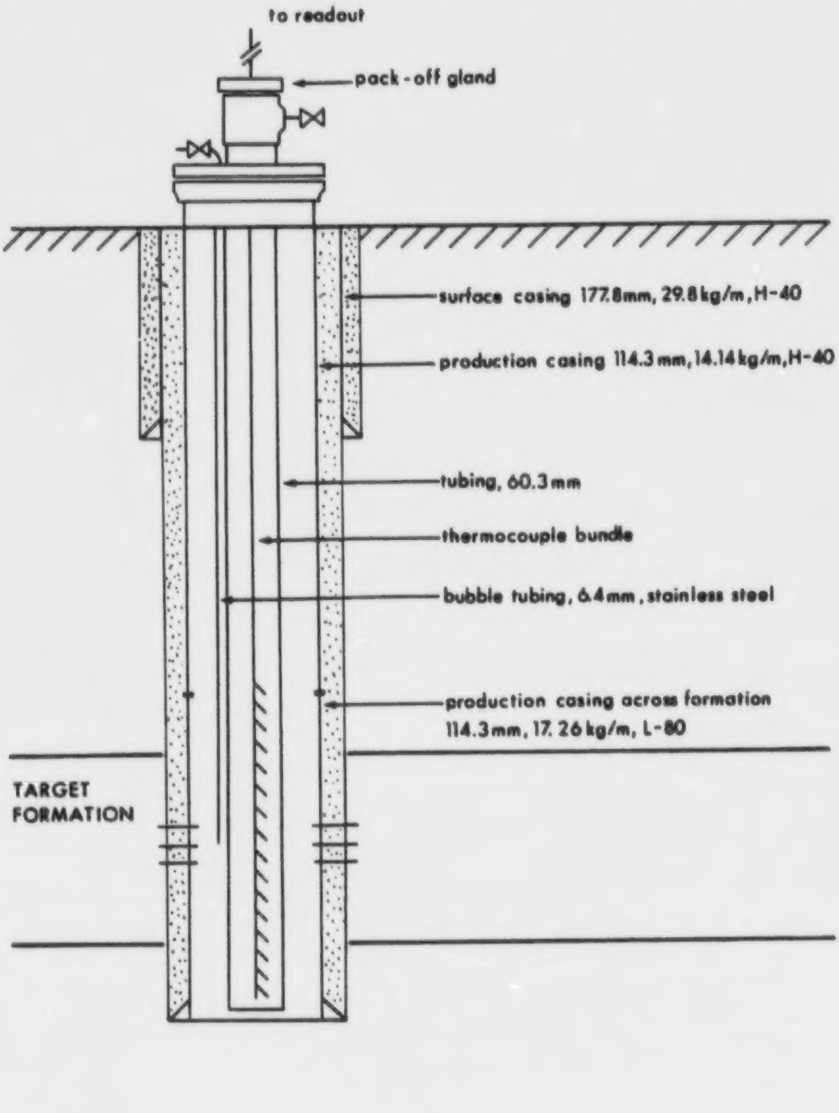

to readout
pack-off gland
surface casing 177.8mm, 29.8kg/m, H-40
production casing 114.3mm, 14.14kg/m, H-40
tubing, 60.3mm
thermocouple bundle
bubble tubing, 6.4mm, stainless steel
production casing across formation
114.3mm, 17.26kg/m, L-80
TARGET
FORMATION

Figure 4
Bottom- Hole Pressure Measurement System

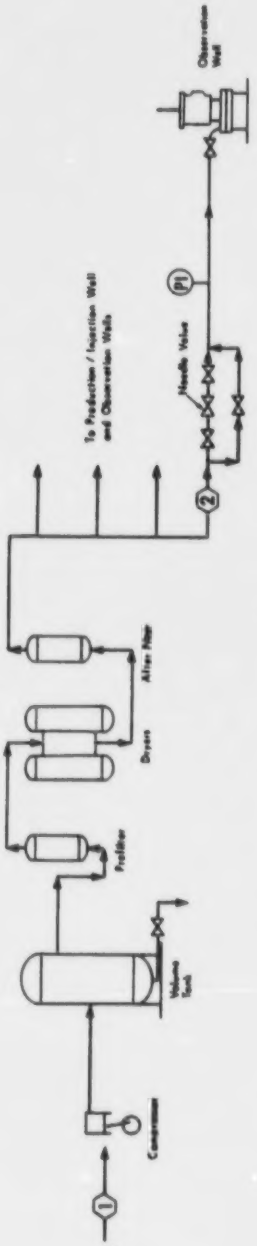
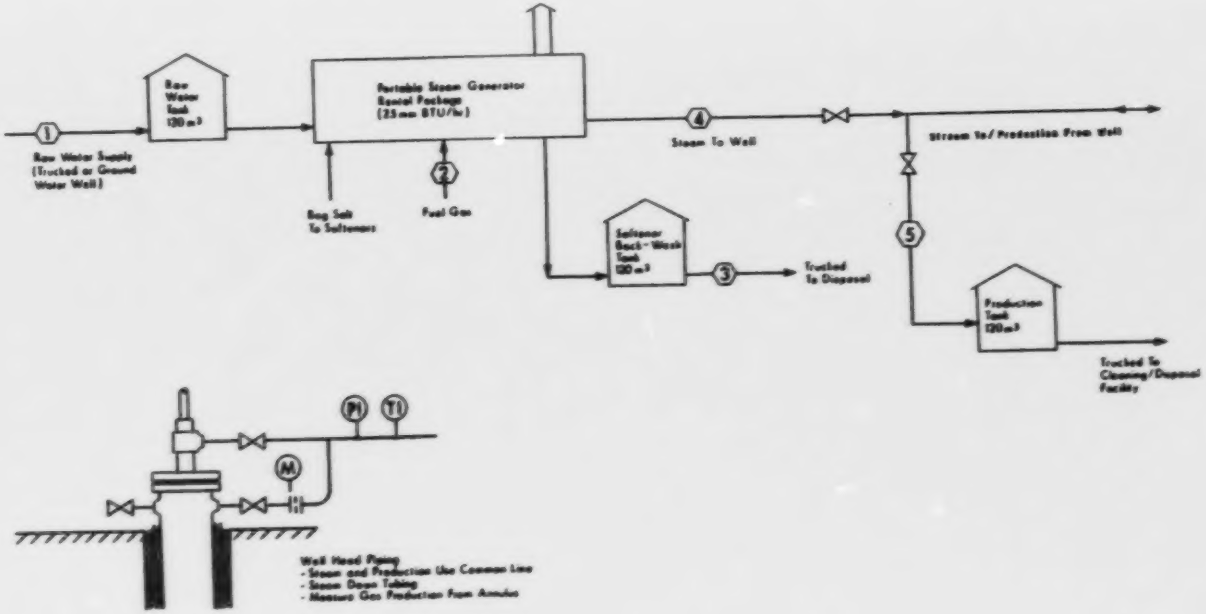

Gas Supply
1
Compressor
Volume Tank
Prefilter
Dryers
After Filter
2
Needle Valve
PI
To Production / Injection Well and Observation Wells
Observation Well

Figure 5
Steaming and Production Process


1
Raw Water Supply (Trucked or Ground Water Well)
Raw Water Tank 120 m³
Portable Steam Generator Rental Package (25 mm BTU/hr)
Bag Salt To Softeners
2
Fuel Gas
Softener Back-Wash Tank 120 m³
3
Trucked To Disposal
4
Steam To Well
Stream To/ Production From Well
5
Production Tank 120 m³
Trucked To Cleaning/Disposal Facility
PI
TI
M
Well Head Piping
- Steam and Production Use Common Line
- Steam Down Tubing
- Measure Gas Production From Annulus

ATTACHMENT 2

EVALUATION OF AN ENHANCED RECOVERY PROCESS FOR A HEAVY OIL RESERVOIR

John H. Nicholls
Nimarec Engineering Ltd.

In considering possible commercial exploitation of a tar sands or heavy oil reservoir, it has become a generally acceptable procedure that the preferred process (as determined by engineering "paper" studies) be tested by a field pilot before making the decision on whether or not to begin commercial scale operations. The preliminary engineering studies always require that a number of assumptions be made so it is highly desirable to check these by field operations before committing large sums of money to a commercial project. The pilot work can provide data in such areas as amount and rate of recovery, reservoir conformance, volumes of injected fluids, equipment performance, operating difficulties, operating costs, etc.

In the past during field evaluation of reservoir processes, the progression of testing has commonly started with an initial single well test followed by an expanded operation encompassing one or more five- or seven-spot patterns. Frequently, the initial test site has not been incorporated into the subsequent patterns. One of the objectives of the second phase (the operation of one or more patterns) has often been the desire to obtain data for input into mathematical simulations, therefore it has been felt desirable to have the pattern in a new area (away from the original test well) in order to have undisturbed reservoir and to have all parts of the pattern at the same state of depletion (ie: no production). It is the writer's view that there is now sufficient multipattern experience to indicate that geological anomalies in the reservoir and operational variations during piloting activities can more than outweigh the concerns involved in attempting to cope with different stages of depletion in different portions of the pilot when analyzing pilot performance. It is a fact that in field operations there are different stages of depletion or different parts of the pilot even when attempts are being made to operate all patterns in a uniform manner. Mathematical and physical models do have a place in providing a qualitative indication of the reservoir performance to be expected from field tests, however they cannot provide definitive answers in regards to reservoir performance as it is impossible to accurately define all the geological and other characteristics of the reservoir being tested. Therefore, after the initial modeling work, a meaningful prediction of expected reservoir performance can best be obtained from the study and interpretation of actual field data.

The foregoing leads to the recommendation that the emphasis during the evaluation of the potential exploitability of the reservoir be placed upon a detailed analysis of data from a progression of field tests, each of which is dependent upon the results from the previous tests. These field tests would be initiated after geological work had defined suitable reservoir and after modeling work had identified a potentially attractive process. The results from field operations should be subjected to a very careful and ongoing detailed examination and analysis of each well's performance. The aim of these studies would be to eetermine "average well performance." A logical succession of pilot wells should provide for the progression towards a more and more meaningful measure of "average well performance" which can then be incorporated into economic studies.

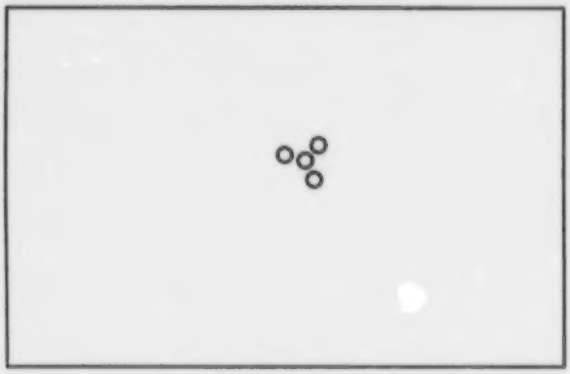
If one accepts the above position, it then becomes reasonable to begin a process and reservoir evaluation with one well, adding wells at appropriate stages as the data indicate the desirability for expanding operations.

To be specific, it is proposed that the evaluation of a potentially commercial steam process for an oil sands reservoir (after the preliminary geological work has defined an interesting area) should commence with a single well surrounded by three closely spaced observation wells operated for a year or so to be followed by three relatively widely spaced wells (suitably located for incorporation into a seven-spot pattern) if good performance is indicated. The four wells would then be operated until sufficient data were available (another one to two years) to determine whether closer spacing was indicated or alternatively the seven spot could be completed for a steam flooding test. Additional wells could be drilled at appropriate times to complete additional seven spots, enclose patterns, or set up almost any direction of line drive.

The following provides brief written descriptions of possible stages in the evaluation of a steaming process (stimulation and/or displacement) as well as diagrams showing possible well locations.

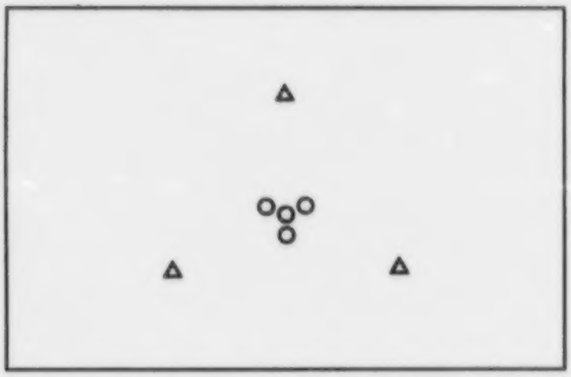
The first pilot stage, after geological and other work has identified a relatively large area representative of a potentially commercial project, would be a single well stimulation test to confirm that the reservoir can produce reasonable volumes of oil. This pilot could have three observation wells located nearby (more or less than 30 meters) to obtain early data on heat movement in the reservoir (Figure 1). The geological information from the observation wells, in addition to that from the central well, would provide data on reservoir variability.

Figure 1



After several cycles on the one well, if the data were encouraging, it would then be appropriate to drill three more wells located at appropriate positions taking into account heat movement in the reservoir, the desirability to test relatively wide spacing, and suitability for eventual incorporation, if desirable, into a multipattern pilot (Figure 2). All four wells would now be stimulated to determine reservoir performance on wide spacing.

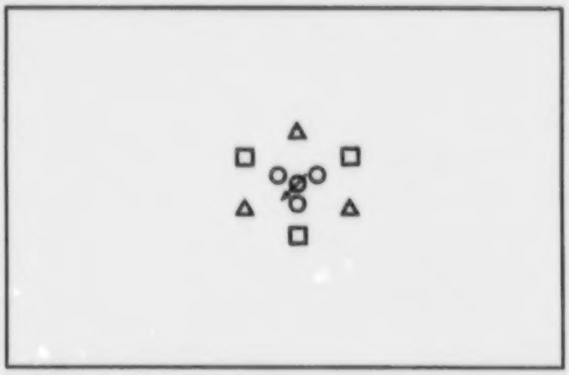
Figure 2



If good communication was demonstrated among all four wells, it would not be necessary to investigate reduced spacing. So the next step, after building confidence through "sufficient" steaming and production of all four wells, would be to add wells to complete the seven spot for displacement tests. There are a number of alternatives at this stage:

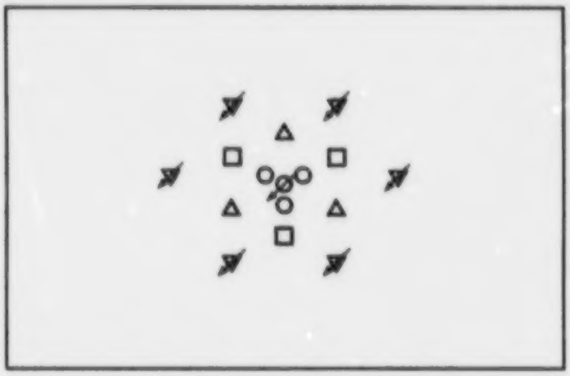
- ☐ *1. Stimulate the new wells and test for displacement efficiency by continuous injection into the central well producing the surrounding locations (figure 3), or,*

Figure 3



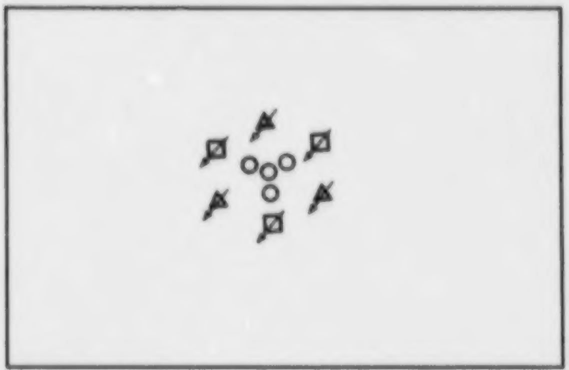
- ☐ *2. Produce the central well while injecting into all the surrounding wells (Figure 4), or*

Figure 4



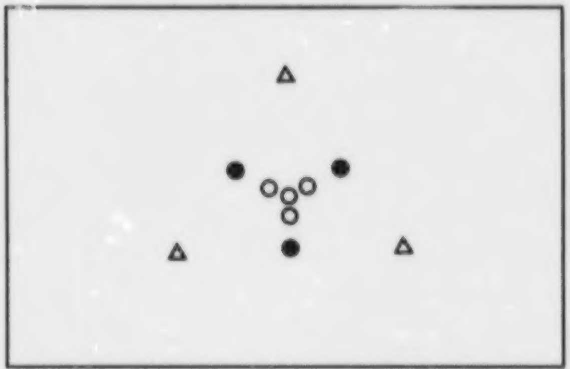
- ☐ *3. Drill six additional wells around the central seven spot and then after stimulating all the new wells, commence displacement tests by continuous injection into the central well plus the six outside wells*

Figure 5



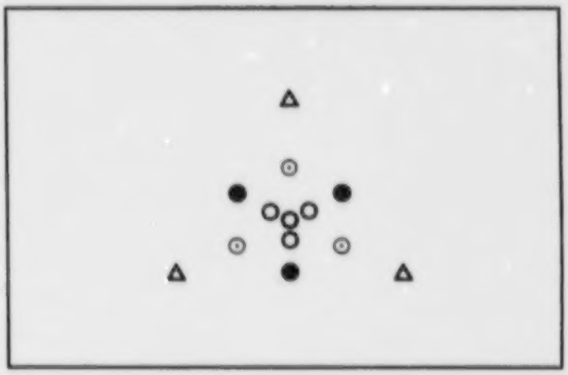
If communication was found to be poor among the four widely spaced wells, indicating the need to consider closer spacing, it would then be possible to halve the spacing by drilling in-fill wells located more or less as depicted in Figure 6. These could then be steamed and tested to obtain data on inter-well communication.

Figure 6



After determining that there were good prospects for a future steam flooding process on this reduced spacing, it would then be appropriate to drill an additional three wells to complete the seven-spot pattern (Figure 7) with the objective of testing displacement. This pilot could either evaluate performance utilizing a single central injector or alternatively the central well could be the producer with the six surrounding wells being the injectors.

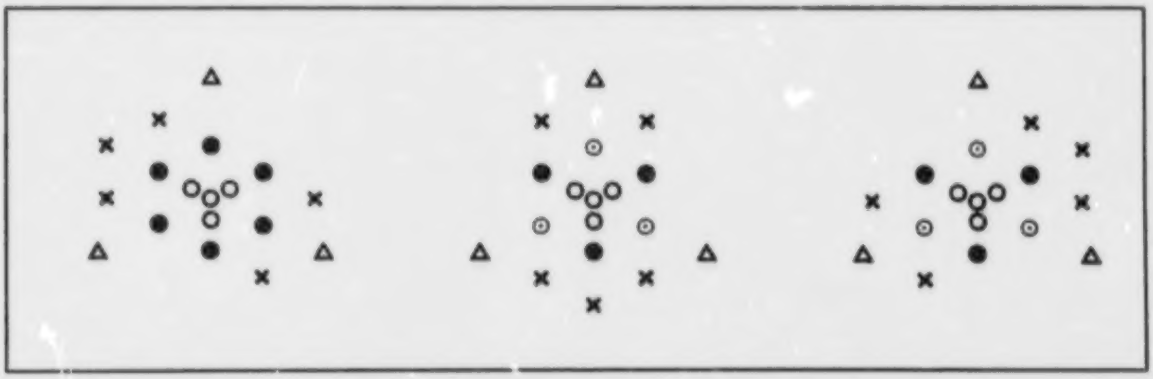
Figure 7



Flooding data may indicate that a pattern flood will not perform satisfactorily due to a preferred direction of flow of injected fluids. If this phenomena is indicated, then additional drilling would readily convert the seven-spot pattern to a line drive configuration as illustrated in the following figures. It can be seen that it would be easy to provide for different possible displacement directions by the appropriate positioning of the extra wells.

The foregoing indicates that if one begins piloting with expansion in mind, it is logical to utilize the test wells in a progression which could culminate in one or more seven spots or even a line drive configuration.

Figure 8



In summary, it is recommended that for a pilot evaluation of the steam stimulation and displacement process for an oil sands reservoir serious consideration be given to beginning field activities with the stimulation of a single well plus three observation wells. After encouraging performance has been achieved, the second stage should be a test of stimulation and displacement with an additional three wells (located to form part of a seven spot) on relatively wide spacing. Performance at this stage would then dictate which of the previously outlined possible expansion alternatives should be considered for expanded experimental work.

SASKATCHEWAN ENERGY AND MINES EOR PILOT PROJECT PROGRAM SINGLE WELL TEST BOTTOMHOLE PRESSURE MEASUREMENT SYSTEM

Flow Stream Number Fluid	Flow Rate Average	Pressure kPa	Temp °C
1 Natural gas	800 m^3/day	1,000	20
2 Natural gas	200 m^3/day	10,000	40

SASKATCHEWAN ENERGY AND MINES EOR PILOT PROJECT PROGRAM SINGLE WELL TEST WITH RENTAL STEAM GENERATOR STEAMING AND PRODUCTION PROCESS

Flow Stream Number Fluid	Flow Rate Average	Pressure kPa	Temp °C
1 Raw water	300 m^3/day	150	10
2 Fuel gas	20 m^3/day	350	10
3 Softener backwash	50 m^3/day	200	10
4 Steam (80% quality)	250 m^3/day*	14000	367
5 Oil/water	38 m^3/day**	700	150

* *Assumes no injectivity problems.*

** *Production based on Pike's Peak results.*

33

SEISMIC MONITORING TECHNIQUES FOR REMOTE SENSING OF HEAVY OIL IN SITU HEAT MOVEMENT

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N. E. Pullin Petroleum Consulting Services Inc.

Robert F. Thorburn

Larry W. Matthews
Amoco Canada Petroleum Company Ltd.

ABSTRACT

Vast resources of untapped tar sands and heavy oil reserves are waiting to be developed when the technology becomes available to mobilize this highly viscous hydrocarbon both efficiently and economically. A good deal of the ultimate success of heavy oil in situ thermal pilots is necessarily related to preliminary knowledge of the reservoir's characteristics, together with reliable imaging of the subsequent subsurface heat movement throughout the life of the project.

Many of the recent developments in seismic technology have indicated encouraging potential for locating these heat zones. Rock properties studies have demonstrated significant changes in the acoustic properties of heavy oil tar sands due to the application of heat which is the foun-dation for most of the seismic techniques.

To date, high resolution 3-D seismic monitoring has demonstrated the most promise although other seismic methods, such as tomography, are still in their infancy and relatively untested.

The results of high resolution 3-D monitoring surveys at the Gregoire Lake Pilot site in northeastern Alberta, Canada demonstrate that by using advanced 3-D field acquisition, processing and interactive computer display techniques, excellent spatial and temporal resolution of a shallow reservoir can be obtained. Comparison of these seismic results,recorded at different times, also reflects the imaging of the heat movement. The integration of this type of data into the design and operation of heat injection projects should help in improving their future viability.

INTRODUCTION

The volume of heavy oil in Alberta is conservatively estimated at 210×10^9 cubic metres with only about 7 percent of the tar sands being accessible with surface mining. Most in-situ projects are confined to reservoirs with oil that is immobile at reservoir temperatures and pressures. With the proper addition of heat, many of these reservoirs can become producible at commercial rates. There are currently 7 commercial and 26 experimental in-situ projects operating in Alberta. Each reservoir has its own unique geology and basic reservoir parameters and, therefore, it is extremely important that maximum knowledge, not only about the reservoir, but also of the heat movement over time be known. Many of the recent developments in seismic technology have indicated encouraging potential for imaging these heat zones. The techniques that are currently being evaluated are microseismic, vertical seismic profiling, tomography and high resolution 3-D seismic. Except for microseismic these monitoring methods are related to significant changes in acoustic impedance caused by heating the reservoir. The recording of a base survey prior to the initiation of an Enhanced Oil Recovery (EOR) process may provide sufficient lithologic detail to aid in the prediction of heat movement.

Recording surveys during the life of a pilot can provide a measure of the project's progress and allow ongoing modification of this process. Up until now, this type of information has been available only by using well data which is extremely sparse when one considers the very complex nature of most reservoirs.

The overall methodology for the seismic monitoring of heat movement over time is very important and should consist of the following:

1. Rock properties analysis,

2. Computer modeling,
3. Seismic field testing,
4. Stratigraphic interpretation from 3-D Base Survey,
5. Heat zone imaging from 3-D Monitor Surveys.

MONITORING TECHNIQUES

The following seismic monitoring techniques, diagramed in Figure 1, have indicated potential for remotely locating heat zones: Microseismic, Vertical Seismic Profiling, Tomography and High Resolution 3-D Seismic.

■ Microseismic

Microseismic refers to those acoustic emissions that cannot be heard or felt by people. These body waves are generated where solid material is being stressed, either by an applied pressure or by a constrained expansion. Phenomena like these have been proposed to exist at thermal EOR sites. The objective of miscroseismic monitoring is to deploy sensors above an in-situ site, monitor the acoustic emissions and then, via a triangulation technique, infer the locations of active heat fronts. Figure 1(a) is a typical field setup showing seismic energy emanating from the EOR fronts and being recorded by geophones on or near the sur-face. Based on testing to date, this technique indicates little potential for unconsolidated tar sands but may be applicable for deeper consolidated reservoirs.

■ Vertical Seismic Profiling

Vertical seismic profiling (VSP) is a measurement technique in which energy produced at the surface of the earth is recorded by a geophone clamped at various depth levels within a wellbore. Because the receiver is located within the earth, it is capable of detecting both upward-travelling and downward-travelling body waves. Figure 1(b) shows a typical field layout with a source located at some distance from the wellbore and another in very close proximity. Various raypaths are shown from the source to the geophone located in the well. The data acquired from the zero-offset (near source) survey can be used to correlate reflection events to the precise depth at which they were generated as well as to produce an earth absorption model. The offset (far source) data set can be processed to produce a high resolution 2-D seismic image away from the wellbore which may provide additional definition not available in normal surface seismic.

■ Tomography

Three types of tomography are shown in Figures 1(c) and 1(d). These are surface-to-wellbore, wellbore-to-surface and wellbore-to-wellbore, traveltime measurements. The objective of tomography is to reconstruct the material properties within a body given a set of measurements gathered at or near its perimeter. Most often, this will mean reconstructing the velocity distribution within the zone of interest from the observed seismic traveltimes through the body.

With surface-to-wellbore tomography a receiver is placed below the zone of interest in a well and seismic energy is initiated on the surface. The traveltime from source to receiver is recorded: one source typically produces one measurement. Wellbore-to-surface tomography, on the other hand having the source located within the well and the receivers on the surface, produces multiple measurements at one time. This type of geometry yields good information laterally but lacks vertical resolution due to smearing of the possible velocity solution along the rays' travel path.

Wellbore-to-wellbore tomography requires sources to be located in one well and the receivers in another. The resultant processed 'Tomogram' would be a 2-D slice or picture of the velocity distribution between the two wells. Again, because of smearing along the seismic travel path, there is a lack of resolution in the horizontal direction. The best tomographic image can be produced with a combination of wellbore-to-surface and wellbore-to-wellbore traveltime data. The results of limited testing of tomographic applications for in-situ monitoring has been very encouraging, but requires additional exposure to various type reservoirs.

■ High Resolution 3-D Seismic

Figure 1(e) is a schematic showing the source and receiver configuration for a 3-D reflection survey. The advantages to this technique for EOR monitoring are numerous. A few of the more important considerations are: the redundancy of information at each common reflection point producing better signal-to-noise data than could be obtained with a single measurement, the areal distribution of information allowing for 3-D imaging of the subsurface, the improved temporal and spatial resolution that this type of data can provide, the successful applications of 3-

D seismic allowing for credible processing and interpretation as well as the cost effectiveness of this method. These factors point to 3-D reflection seismic as the most cost effective, reliable way to monitor insitu EOR processes at this time.

■ Gregoire Lake Pilot

The Gregoire Lake In-Situ Steam Pilot (GLISP) project is located in northeastern Alberta, as shown on Figure 2 and was designed to test a steam stimulation process. The geology of the GLISP site as shown in Figure 3 depicts the sonic response of the tar sands reservoir. The formation being steamed is a discontinuous 50 metre thick sandstone of Cretaceous age. This sandstone, commonly referred to as the McMurray (MCMR), contains 8°API oil and rests on the Devonian (DVNN) unconformity approximately 235 metres below the surface.

■ Rock Properties

Rock properties studies are an imperative first step to understanding the tar sands' acoustic response to the application of heat. Numerous tests have been conducted on core samples obtained from the Athabasca tar sands. Figure 4, taken from Tosoya and Nur, 1984[2], demonstrates the significant decrease in compressional velocity as the temperature of the tar sands is increased. In this particular case the velocity was lowered by as much as 60 percent of its ambient reservoir velocity when heated to 200°C. While this may be an extreme case, other work has shown P-wave velocity decreases of 30 percent are not uncommon with modest temperature increases. The magnitude of the decrease appears to be related to the tar saturation; the higher the saturation, the larger the velocity decrease.

The significance of this change in velocity is that:

1) The top and bottom of the heated tar sand will act as acoustic reflectors.

2) Seismic reflections below the heated zone will be delayed in time, a phenomenon referred to as 'pushdown'.

COMPUTER MODELLING

In order to simulate the seismic response for heated tar sands, computer modelling was done combining both sonic logs and rock properties information. Figure 5 is a model showing the seismic response of a wedge of Page 5 75°C hot tar sand increasing in thickness from 0 to 20 metres. This model demonstrates:

1) the boundaries between the hot and cold tar sand produce significant reflections, and

2) pushdown is observed immediately below the heated tar sand on the DVNN reflection.

Based on this model one might expect to resolve a heated tar zone as thin as 5 metres using 175 Hz high signal-to-noise seismic data. If higher frequencies can be recorded then, naturally, the resolution should improve. The other important effect is pushdown which should outline the areal extent of the heated zones and provide an estimate of their net total thicknesses. It must be remembered, however, that this is a noise-free model, which is unachieveable in the real world.

■ Seismic Field Testing

A comprehensive set of seismic field tests were conducted at the pilot site in October 1984. The purpose of these tests was to determine the optimum field acquisition parameters which would produce 3-D data of exceptionally high quality. Results indicated that by using buried seismometers and very light charges, both located beneath the muskeg, a dramatic improvement in the signal-to-noise ratio and high frequency content of the field data resulted[1]. Figure 6 shows unprocessed fieldprofiles comparing the surface and buried seismometers demonstrating the excellent correlation between synthetic seismogram and the subsurface field data.

■ 3-D Seismic Monitoring

Figure 7 shows the field recording geometry used relative to the well configuration. The survey area is 168 x 228 metres which includes an expansion to the east for the monitor as compared to that used for the base survey. This was necessary because of an alternation to the originally planned well pattern. This recording geometry generated a minimum of 1200 percent coverage for each 4 metre x 4 metre common depth point bin, except near the perimeter. The geophones are designated by the symbol "+" and the sources by the symbol "x". To facilitate reloading of the shot holes for future surveys, plastic casing was used. Using optimum acquisition parameters determined from the testing a 3-D base and monitor survey were acquired which resulted in exceptionally high quality field data. Similar acquisition and processing were employed for both surveys. A 120 channel Sercel 348 telemetry system using a one millisecond (ms) sample rate was used for recording both data sets. Based on extensive testing of the base survey the final processing flow included "Q" compensation for attenuation losses, surface consistent deconvolution and 2-D x 2-D post-stack migration. In addition, an all-pass, phase-correcting filter was applied to the monitor because the final phases of the two data sets were not identical. This difference was probably due to the seasonal variance in muskeg conditions between the two surveys and is believed to have effected the ghost, and thus, the recorded wavelet. The 3-D results indicated excellent temporal and spatial resolution by locating a narrow, yet important Devonian erosional channel. This excellent resolution will also aid in the stratigraphic interpretation by potentially enabling the mapping of lithologic zones where heat may preferentially migrate and accumulate.

■ Interpretation

An interactive workstation was used to interpret both 3-D data sets. One effective 3-D display is the isometric projection of the Devonian unconformity surface extracted from the base survey (Figure 8). The narrow erosional channel, highlighted in blue, demonstrates both the spatial and temporal resolution obtainable. The excellent resolution of the reservoir's thin stratigraphic lenses is emphasized by the "chair" projection shown in Figure 9. Here we have removed a cube of the data, which enables us to see not only an expression of the channel itself but also a cutaway of the tar sands section. One should have little difficulty in thinking that this reservoir is heterogeneous, discontinuous and ordered. Another effective means of studying the geology is with a series of time slices. Time slices display a flat horizontal cut through the entire 3-D data volume at a specific time as opposed to vertical cuts which produce the normal 2-D seismic profile. Figure 10 is a display of time slices at 1 millisecond intervals, which is approximately equivalent to one metre. The 224 slice best depicts the N-S erosional channel which is confirmed by the H-3 well. The HO-7 well is high on the unconformity and interpreted to be at the edge of the channel.

A processing technique which has tremendous potential to assist in stratigraphic interpretation is seismic inversion. Inversion is the math-ematical process which attempts to convert the seismic trace to its acoustic impedance representation. Figure 11 is a schematic demonstrating the basic concept of inversion where combining velocity and density results in acoustic impedance. Reflection coefficients which are a measure of the acoustic impedance contrast between one reflective layer and another are modified by an earth filter resulting in the recorded seismic trace.

Figure 12 shows a 2-D line extracted from the 3-D seismic base survey which has been inverted to its pseudo-acoustic impedance representation. The H-3 and HO-7 impedance logs have been inserted into the line at their appropriate location and generally show a good correlation to the field data.

Two criteria important to the interpretation of the heated zones from the monitor survey are: push-down, and character changes occurring within the tar sand section. Both of these effects can be observed when comparing the base (pre-steam) to the monitor (post-steam) surveys.

Figure 13 illustrates a comparison of 2-D seismic cross-sections extracted from both the base and monitor 3-D data sets illustrating the predicted seismic expression of the heat zones.

For horizons below the reservoir, the seismic wavefront may travel through a heated interval. The velocity decrease due to heating the tar sands will cause a delay in the arrival time for all seismic ray paths which pass through this zone and are reflected back. To map this push-down, a reflector above and below the reservoir was timed on both the base and monitor surveys. Travel times through the McMurray interval were consistently delayed on the monitor survey near injection wells as expected. Pushdown can be observed on the east-west section extracted from both 3-D data volumes which tie well H-5 as shown by Figure 13. The pushdown map, as shown in Figure 14, is contoured only for pushdown greater than 2 milliseconds and exhibits a pattern that correlates to the injection well locations. This map, while indicative of the areal extent of heating, does not provide vertical resolution and is not directly correlatable to temperature and/or thickness of the heated zone. Pushdown is dependent on two variables, thickness and velocity, with velocity dependent on temperature. As a result, it is not possible to use pushdown alone to predict thickness without first knowing temperatures and vice versa.

Seismic amplitude, or signal strength, is directly proportional to the change in acoustic velocity and density at an interface. As the tar sands are heated, the velocity will decrease, and the amount of this decrease will be directly related to the magnitude of the temperature change. This phenomena means that a heated zone, if thick enough, should show a change in seismic character when compared to the base survey. Although interpretation of these amplitude changes is not finalized, one possible example of this effect can be observed in Figure 13. An event at 0.2 seconds on the monitor survey, which is postulated to be the result of steam injected into H-5, is not apparent on the base data set.

As seismic amplitude is directly linked to acoustic changes, both 3-D data sets were mathematically inverted and colour coded to provide a pseudo-acoustic impedance (velocity x density) log for each seismic trace. Relative acoustic decreases, which should represent heat on the monitor survey, can then be interpreted directly from the inverted data sets. Acoustic variations on the monitor are sensitive to both temperature changes and lithology. In order to isolate the changes due only to heat, the monitor inversion was subtracted from the base inversion, to produce a difference data set. This should isolate the heated zones. A technique for illustrating the vertical and horizontal distribution of the heat within the reservoir is accomplished by snapping a sequence of time slices through the inverted 3-D difference data set. Figure 15 is a time slice of the pseudo-impedance difference which indicates areas where the monitor survey has significantly lower impedance values than the base survey. This evidence of heat correlates to independent tem- perature measurements in the observation wells which indicates heat rising through the McMurray Formation.

The inverted seismic base survey contains acoustic impedance changes both laterally and vertically, caused by lithologic variations. Analysis of borehole log and core data indicates that velocity and density changes are due to both porosity and shale percent volume changes in the reservoir interval. Well log acoustic impedance variations appear to correlate with pseudo-impedance trends evident on the inverted seismic. If these lithologic trends can be mapped and their influence on steam propagation confirmed by monitor surveys, this would be a valuable source of engineering data to be utilized in reservoir modelling prior to injection.

CONCLUSIONS

Rock properties studies have indicated significant changes in the acoustic properties of heavy oil tar sands due to the application of heat. This change is the fundamental criteria for the application of most seismic methods. Various seismic monitoring techniques have been evaluated for the purpose of imaging heat movement with high resolution 3-D seismic currently showing the most promise.

High resolution 3-D seismic surveys obtained at the Gregoire Lake Pilot using optimum field acquisition, processing, and display techniques indicates considerable potential for not only mapping the heat movement but for remote imaging of the reservoir lithology.

The integration of this type of data into the design and operation of heat injection projects should help in improving their future viability.

ACKNOWLEDGEMENTS

We are very grateful to the many contributors from Amoco Production Company Ltd. and Western Geophysical for their guidance and encouragement. The authors also acknowledge a debt to Amoco Canada Petroleum Company Ltd., Alberta Oil Sands Technology and Research Authority and Petro-Canada Inc. for permission to present this material.

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Figure 1
Seismic Monitoring Techniques

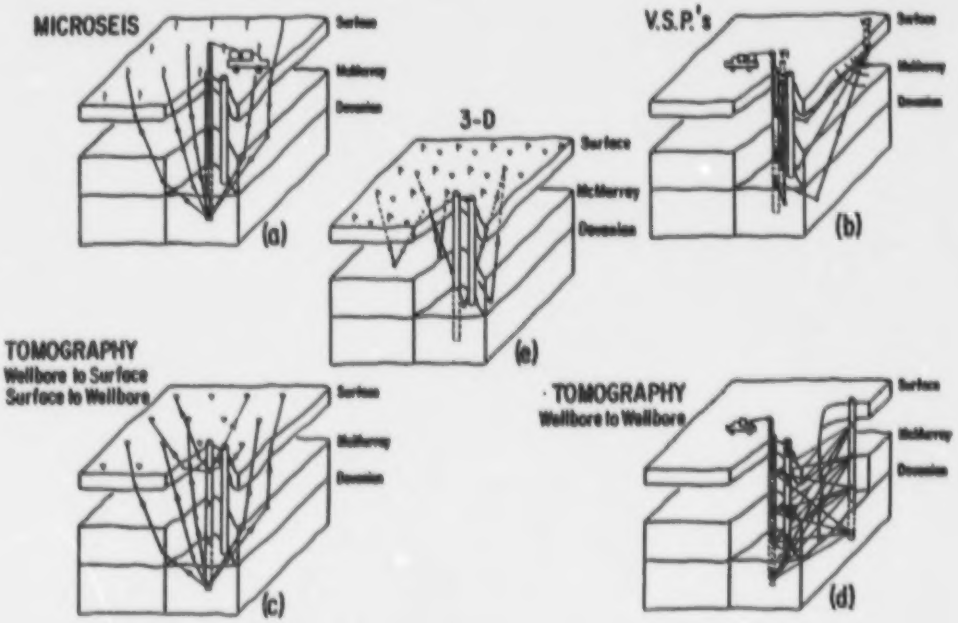

MICROSEIS
Surface
McMurray
Devonian
(a)
3-D
Surface
McMurray
Devonian
(e)
V.S.P.'s
Surface
McMurray
Devonian
(b)
TOMOGRAPHY
Wellbore to Surface
Surface to Wellbore
Surface
McMurray
Devonian
(c)
TOMOGRAPHY
Wellbore to Wellbore
Surface
McMurray
Devonian
(d)

Figure 2
Distribution of Heavy Oil Resources (210 x $10^9 m^3$) in Alberta and Location of GLISP Pilot Site

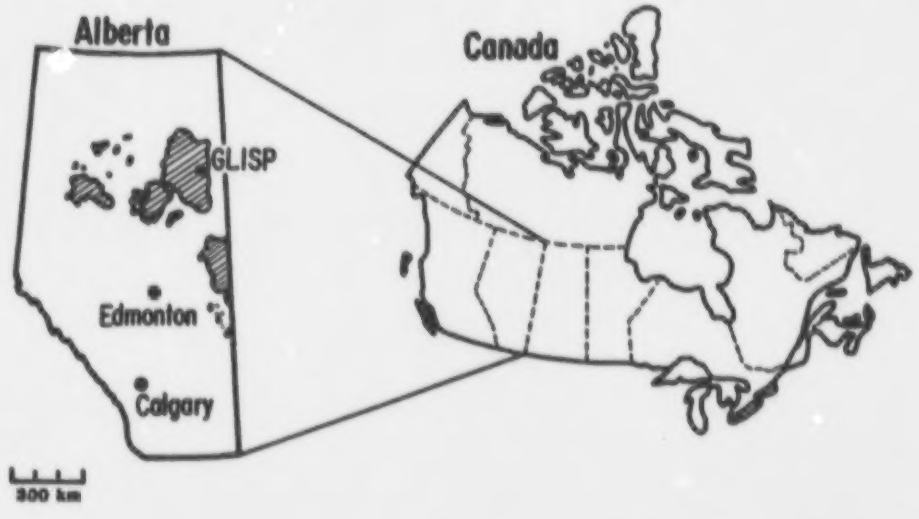

Alberta
Canada
GLISP
Edmonton
Calgary
300 km

Figure 3
Geologial Cross-Section

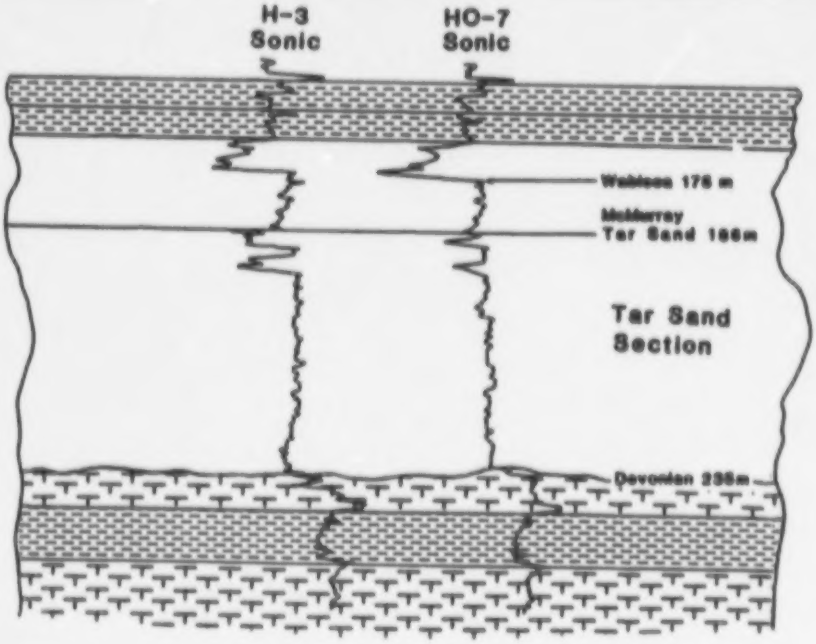

H-3
Sonic
HO-7
Sonic
Wabiscaw 176 m
McMurray
Tar Sand 186m
Tar Sand
Section
Devonian 238m

Figure 4
Velocity vs Temperature (Tosoya and Nur, 1984)

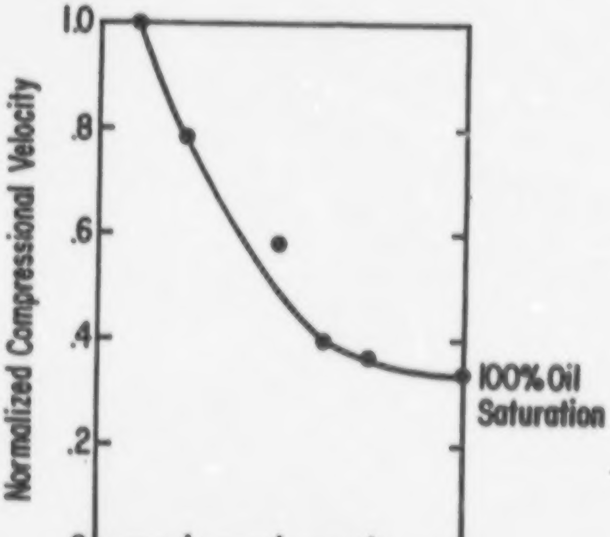


Figure 5
Synthetic Seismeic Model Showing Response to Heated Wedge of Tar Sands Illustrated in Depth Cross-Section

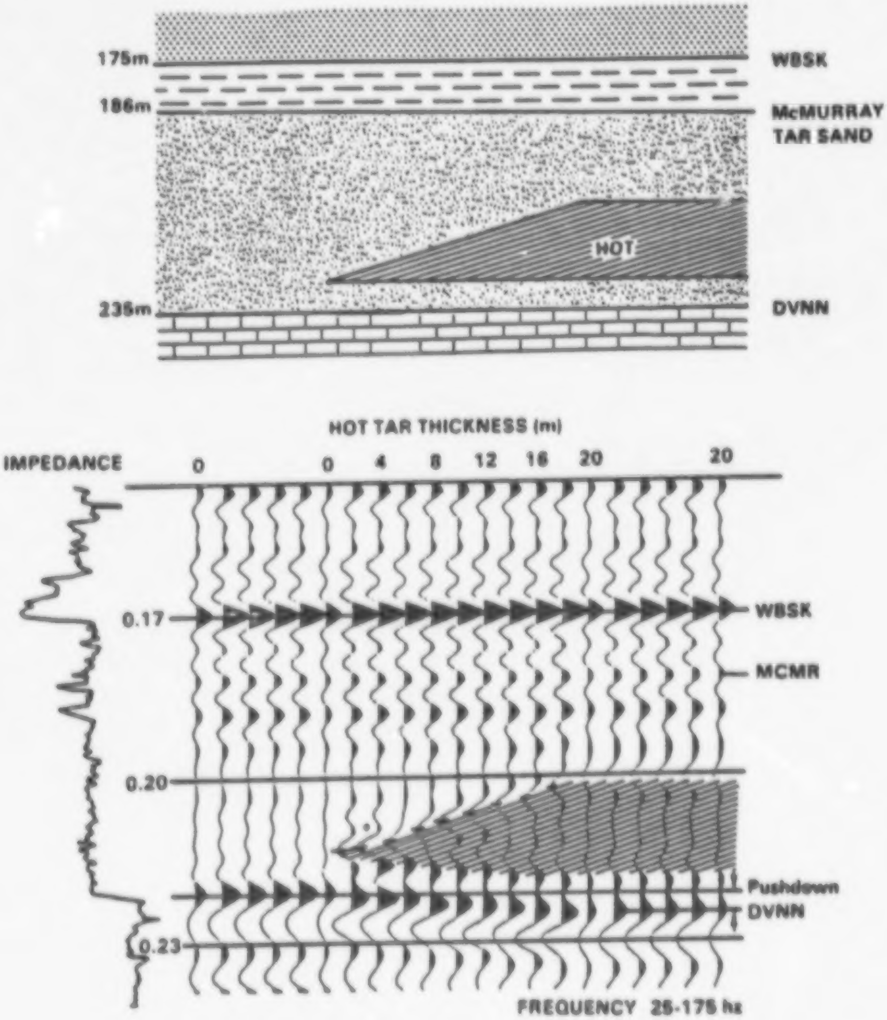

175m
186m
235m
WBSK
McMURRAY TAR SAND
HOT
DVNN
HOT TAR THICKNESS (m)
IMPEDANCE
0
0
4
8
12
16
20
20
0.17
0.20
0.23
WBSK
MCMR
Pushdown
DVNN
FREQUENCY 25-175 hz

Figure 6
Comparison of H-3 Synthetic with Surface Phone and Buried Phone Shot Records Generated by a 50-g Source at 13m Depth

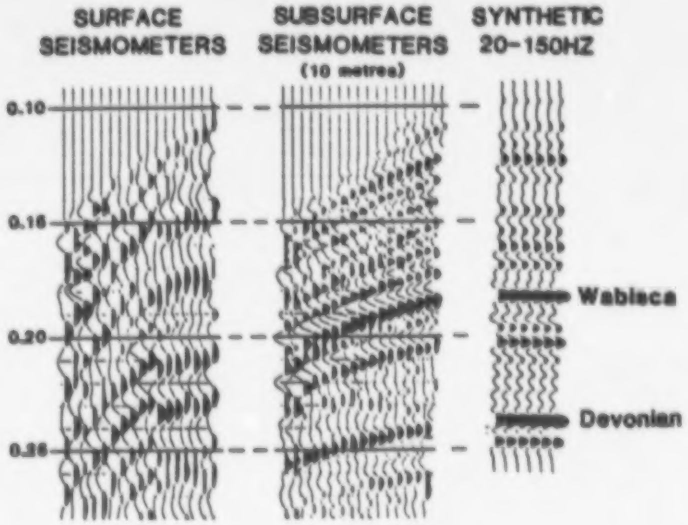


Figure 7
GLISP 3-D Plat Showing Well Configuration, Source and Receiver Locations, and Portion of Stacking Cell Grid

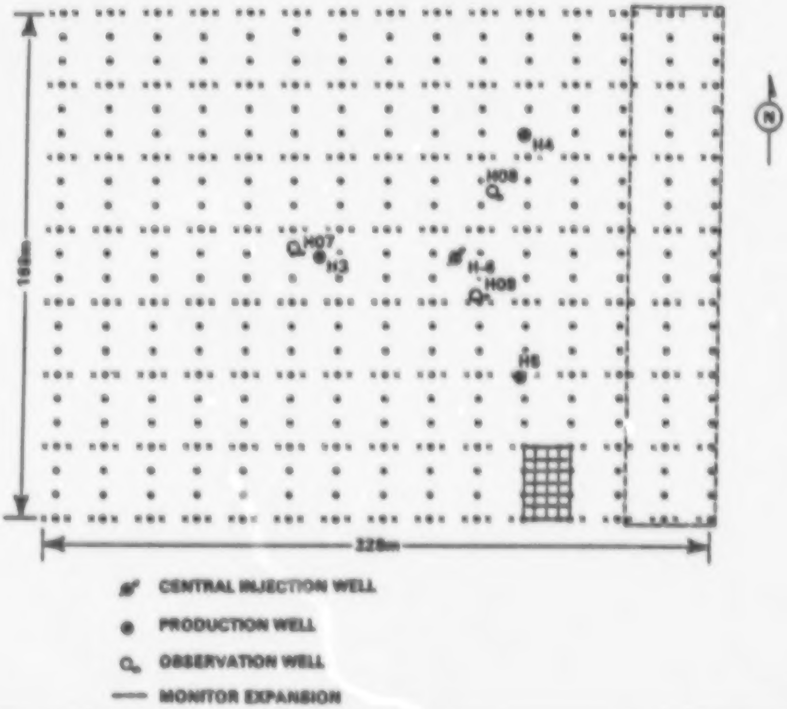

180m
228m
N
H4
H08
H07
H3
H-6
H09
H5
CENTRAL INJECTION WELL
PRODUCTION WELL
OBSERVATION WELL
MONITOR EXPANSION

Figure 8
Isometric Display of the Devonian Time Structure

Figure 9
"Chair" Display of a Portion of the Migrated 3-D Base Data Set. The "Seat" is at the Top of the Devonian

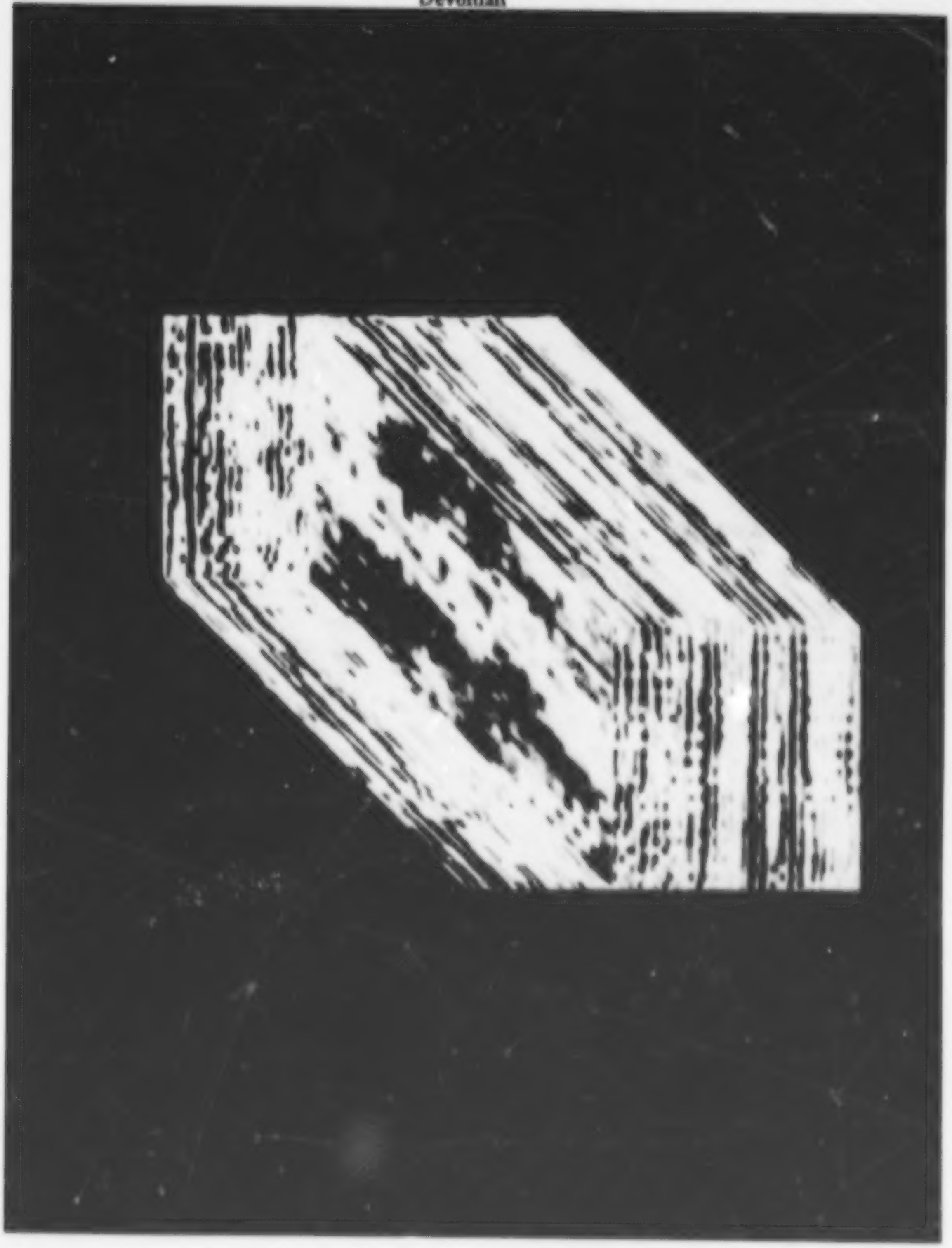


Figure 10
Devonian Time Slices (3-D Migrated Data)

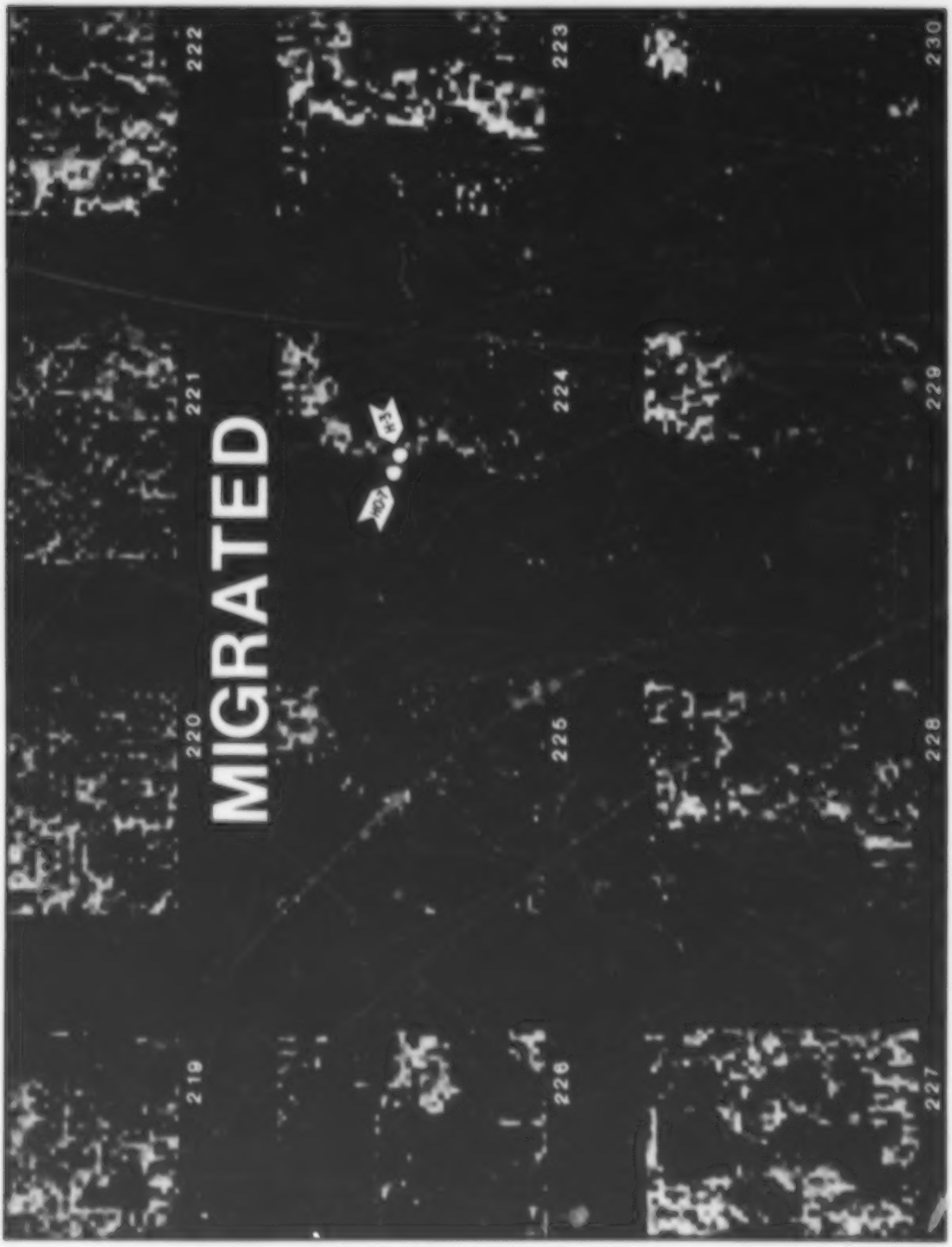


Figure 11
Principles of Inversion

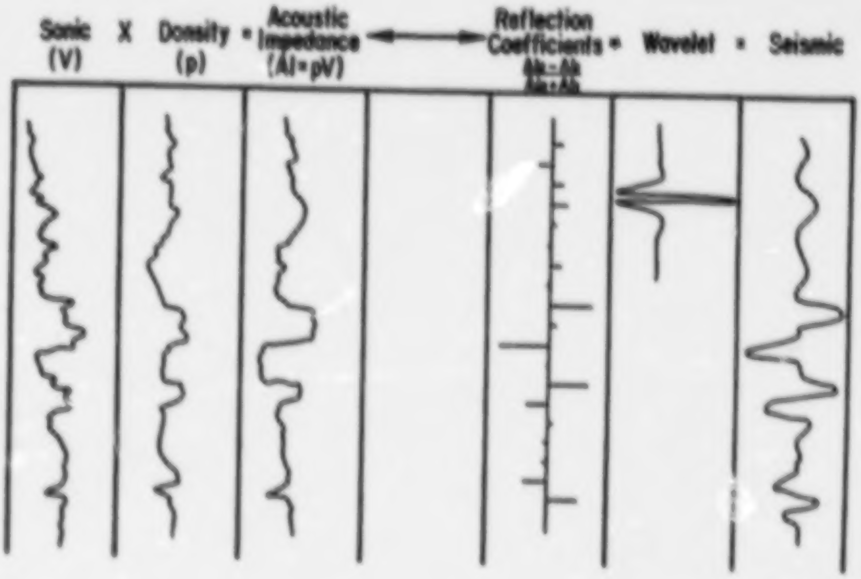

Sonic (V)
X
Density (ρ)
=
Acoustic Impedance (AI=ρV)
Reflection Coefficients $\frac{AI_2-AI_1}{AI_2+AI_1}$
*
Wavelet
=
Seismic

Figure 13
Comparison of Base and Monitor Seismic Sections

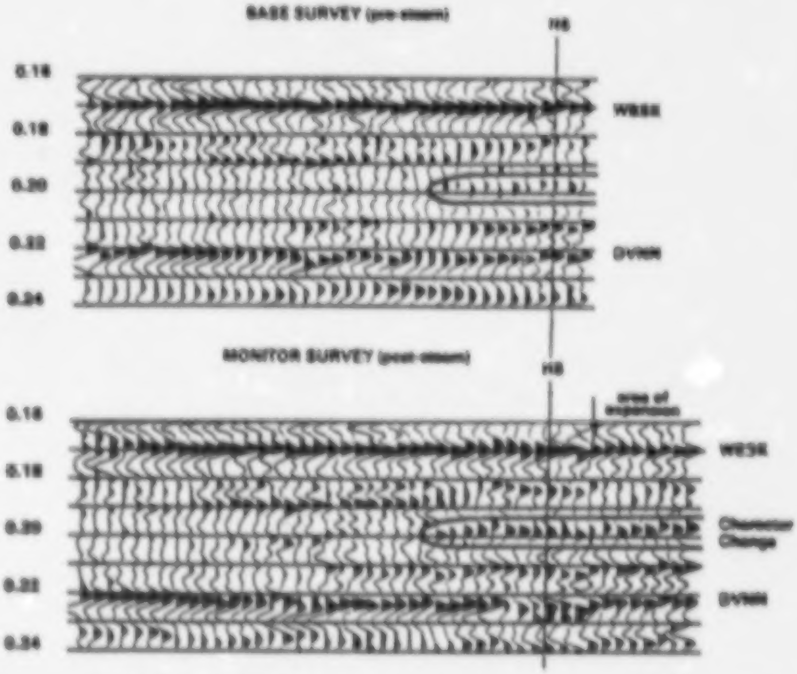


Figure 12
GLISP Inverted Section

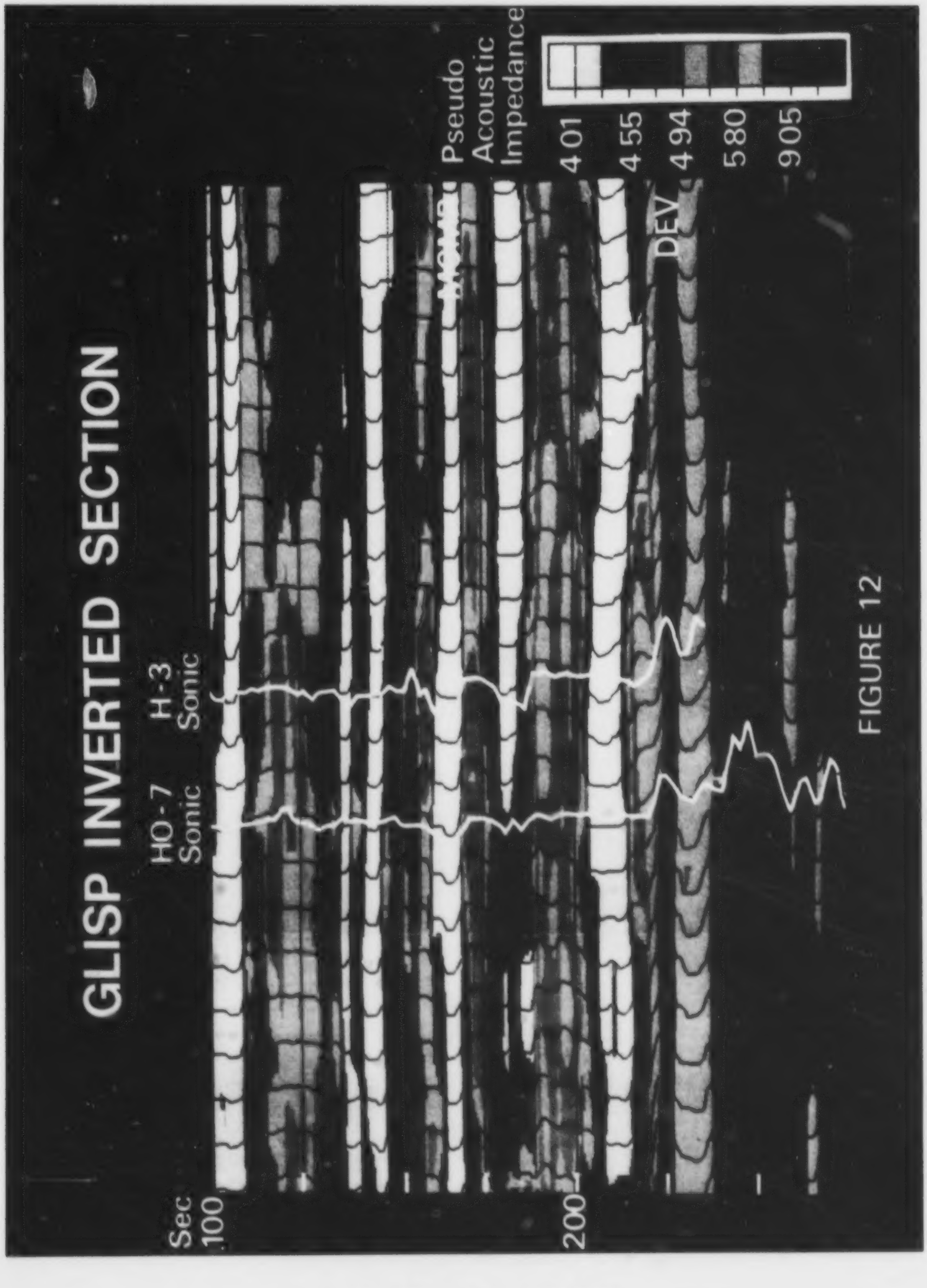
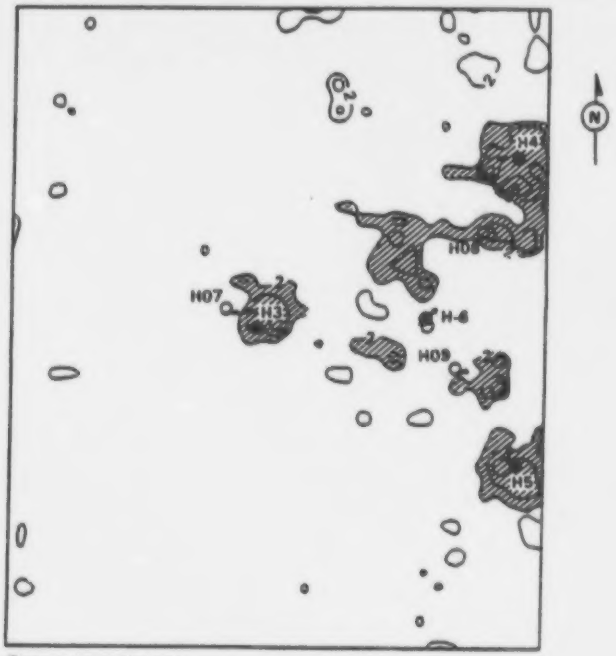
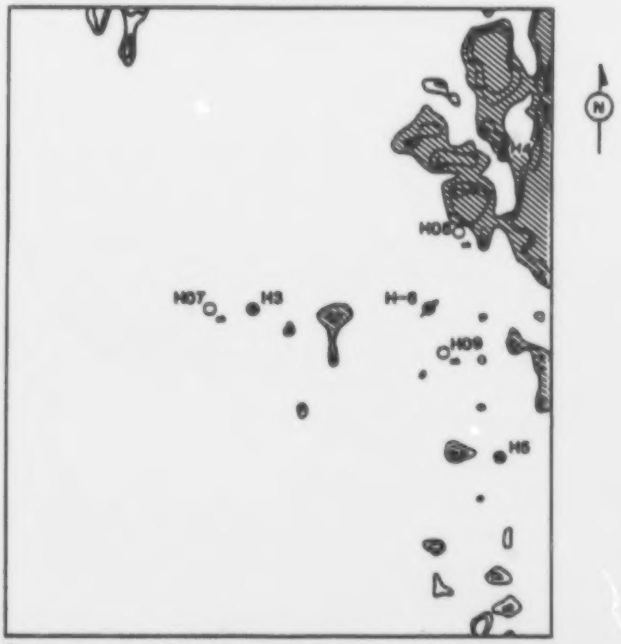


Figure 14
Pushdown Map Illustrating Areal Distribution of the Heated Tar Sands


H4
H08
H07
H3
H-6
H09
H5
2
N

Contour interval = 1 ms

Figure 15
Timeslice of Difference in Pseudo-Impedance (Base minus Monitor) Indicating Heated Zone at 0.192 sec


H4
H08
H07
H3
H-6
H09
H5
N

Contour interval = 30 impedance units.

34

QUANTITATIVE APPLICATION OF SEISMIC DATA FOR HEAVY OIL PROJECTS

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ABSTRACT

Seismic inversion techniques were applied to some data from a heavy oil pilot project in the Cold Lake Heavy Oil region of Eastern Alberta. The original seismic data used in the study were acquired on a heavy oil lease from the Marguerite Lake stimulation project in Township 66 Range 5W4. This pilot project has operated for several years and provided an excellent opportunity to evaluate the effectiveness of using seismic techniques to measure movement of the stimulation front. Seismic surveys were conducted in successive years to determine whether observable changes could be recognized within the reservoir (Clearwater sands) units. Data from this 3-D grid were reprocessed from field tapes to enhance the frequency content necessary for inversion. The results of this study indicate that quantitative data can be obtained which relate directly to the stimulation of the reservoir units. This paper will discuss the factors which influence the ability of seismic data to measure stimulation effects. These factors include reservoir parameters, stimulation techniques, acquisition parameters, seismic processing, and quantification of the results using inversion (Seislog). Specific examples of data from the Marguerite Lake pilot project will be used to illustrate these factors.

SUMMARY

The area discussed in this paper is located (Figure 1) in the northwest part of the Cold Lake Heavy Oil Deposit of Alberta. The Cold Lake Oil Sands occur in the Lower Cretaceous-Mannville Group and cover an area of just over 9,000 sq kms in East Central Alberta. The Marguerite Lake Pilot Project, within Section 8 of Twp. 66, Rge. 5W4 (Figure 1), was designed to evaluate the effects of steam stimulation followed by wet combustion to improve oil recovery in the Clearwater Formation. The project is now in its fifth year of operation and the initial phase (steam stimulation) is essentially complete.

The oil sands of the Cold Lake deposit occur in four members of the Mannville Group (Figure 2); Upper Grand Rapids, Lower Grand Rapids, Clearwater and McMurray Formations. The McMurray is composed mainly of non-marine, well sorted, mature quartzose sandstones interpreted to be channel fill-point bar deposits. The Clearwater was deposited during a transgressive period and is composed of a marine "salt and pepper" sandstone containing some glauconite. Thick marine bar sands and inter-bar sands, silts and shales make up the Clearwater Formation in this region. The Lower Grand Rapids Formation represents a period of northward progradation following the clearwater deposition. Clastics in this formation represent a prograding deltaic sequence composed of delta plain and channel deposits. The Upper Grand Rapids represents a gradual return to transgressive conditions and contain beach deposits, shallow marine bar sands and occasional thick channel sands. An ERCB study, (1974), indicated that 48% of the in-place oil-reserves are in the Lower Grand Rapids, 25% in the Upper Grand Rapids, 20% in the Clearwater and about 7% in the McMurray. This paper will focus on the Clearwater Formation in the Marguerite Lake area (T66, RS W4M).

The heavy oil zone, being stimulated at the Marguerite pilot project, occurs in the Clearwater Formation which has been subdivided into three sand reservoir units (Figure 2): Cl, C2 and C3. The Clearwater at a depth of 460 m is 35 m thick. The C3 zone is the thickest sand and contains the most oil. The Clearwater lies upon the Basal Cretaceous McMurray which in turn rests unconformably upon Devonian Beaverhill Lake carbonates. Shales of the Colorado Group and clastics of the Grand Rapids Group make up the post Clearwater stratigraphic succession.

Seismic data used in this study were acquired in the summers of 1980 and 1981. This 3-D survey was established to obtain two sets of data recorded under identical field acquisition parameters. The inversion (Seislog) processing of three lines from these data was undertaken from field tapes in order to quantify the results of these surveys. The specific objective was to determine the extent of steam stimulation in the Clearwater reservoir sands and the movement of this front. The seismic processing enhanced the high-frequency spectrum of the data to optimize vertical resolution. Phase distortion was studied and corrections were made to compensate for recording instrument and earth filter distortions. The data were then passed through a modified homographic zero phase frequency domain deconvolution. Low-frequency information was derived from well data in the study area to provide frequencies below the cutoff of the recording instruments. The resultant data from the inversion processing were displayed in color and depth.

The key to a successful inversion (Seislog) study is the integration of sonic log data from nearby wells into the results. This allows lithological information to be used in correlating the Seislog traces. Sonic and density logs from two wells were digitized, filtered, and displayed using the same parameters as the Seislog data. Comparison of absolute depth values, transit-time values, and character between the filtered sonic log displays (plotlogs) and the Seislog traces allows calibration of the seismically derived (Seislog) data. Before discussing the results of Seislog processing, it would be beneficial to review the inversion process.

The inversion of seismic trace data to derive impedance logs in the time domain is not a new concept. However, the construction of pseudo-sonic logs from seismic data that are scaled for interval transit time in the depth domain was developed by R.0. Lindseth in 1972. Conceptually, the inversion process is best understood when compared to the procedures used to construct a synthetic seismogram. Generation of a synthetic seismogram follows a route, herein called the FORWARD MODEL (Figure 3) . Inversion is essentially the reverse of this model. In the FORWARD MODEL, the interval-transit-time data of the sonic log are transformed into the time domain and converted to reflection coefficients using the relationship

$$Rc_1 = \frac{{}_2{}^{V}2 - {}_1{}^{V}1}{{}_2{}^{V}2 + {}_1{}^{V}1} \qquad \frac{V_2 - V_1}{V_2 + V_1}$$

The reflection-coefficient series derived from velocity alone gives a close approximation to the reflection-coefficient series of the stratigraphic sequence. Convolution of this reflection- coefficient series with a suitable wavelet produces a synthetic seismogram that can be correlated directly with seismic data. The quality of the correlation depends primarily on the accuracy of the sonic logs and selection of an appropriate wavelet. This model Presents an effective means of equating borehole units to their seismic equivalent. Although an excellent interpretation is possible at the well tie, the synthetic seismic trace is not as effective in evaluating the stratigraphic significance of changes in seismic character lateral to the well.

The INVERSE MODEL (Figure 4) uses the seismic reflection coefficients to derive the velocity using the relationship:

$$V_2 = \frac{V_1 (1 + Rc_1)}{(1 - Rc_1)}$$

This approach, in contrast to the FORWARD MODEL, assumes that the effects of the wavelet can be removed from the data so that the resulting reflectiOn-coefficient series is comparable to that of the stratigraphic sequence.

In order to calculate absolute velocity and depth from seismic data, we must derive the reflection-coefficient series and estimate a velocity at some point in the series. When these calculations are made, powerful and detailed correlations can be observed between stratigraphic units measured with the sonic log and those recorded by the seismic wave. In addition, accurate measurements can be made of interval velocities (transit times) and their relation to lithology-porosity variations large distances from the well ties.

There are significant differences in frequency bandwidth between seismic data and sonic logs. High-resolution reprocessing and frequency deconvolution can restore the amplitude of the higher frequencies in the seismic data so that the reflection-coefficient series from seismic data will match more closely that from the well data.

Because raw sonic logs, before integration, can contain data with frequencies well above the seismic limits (up to 500 Hz), it is necessary to bandpass filter the sonic logs before correlation with seismically derived data. The filtering of a sonic log aids in determining the resolution limits of units and acts as a model for constructive and destructive signal interference effects. Sonic logs are also displayed in a time/velocity format that allows phase checks between well and seismic data to determine the correct polarity for the final displays.

A relative-acoustic-impedance section, expressed in units of velocity and time, represents an intermediate step in the Seislog process. It is at this point that estimates of starting velocities for the series of reflection coefficients, and any phase adjustments are made. This display contains frequency data only above 6 Hz, obtained by a frequency deconvolution. To convert to depth, an estimate of the frequencies from 0 to 6 Hz must be made from stacking-velocity data, well data or velocity modeling, and combined With the higher frequency data. This process is used to generate a depth/transit-time display. Transit-time values can be contoured and colored to conform with standard stratigraphic codes. Normally, green colors represent the slowest velocities (high transit time) and blues/purples the fastest.

In any inversion study, it is important to determine the limits of the method. Critical factors in this study were acoustic-impedance contrast, thin bed resolution and repeatabilty. Impedance contrast refers to changes in density and velocity within the stimulated interval compared with unstimulated reservoir conditions. stimulation will reduce the impedance in the reservoir unit. The amount of reduction is related to the duration of the stimulation. The seismic response will be *inversely* related to the elapsed time between end of stimulation and start of seismic data acquisition.

Resolution is controlled by many factors: depth, frequency content, bed thickness and lateral extent. Published formalae are available to calculate vertical and horizontal resolution given the frequency content of the data and the interval velocity at the zone of interest. For the Marguerite data, vertical resolution is about 8 mand horizontal resolution (or the Fresnel zone) is about 80 m. Well data confirm the presence of signal distortion caused by interference between thin high and low velocity units below the resolving power of the data. Figure S shows the log data for one of the wells in the Study area. There are three curves - the left one represents the unfiltered sonic input which contains up to 250 Hz of information. The middle curve shows the effects of a 100 Hz high cut filter on these data. Notice how the resolution has been decreased and that responses are *averaged* over large intervals, losing some of the detail of individual thin units. Finally, the curve on the right shows the effects of density on the sonic data. This represents an improvement because the seismic data and the resultant reflection coefficients are related to acoustic impedance (velocity and density) rather than velocity alone. Obviously, this product log matches the Seislog data better than the filtered sonic alone. Units with lateral extent less than the Fresnel zone (80 m) become undetectable but contribute to signal distortion. The conclusion is that variations of indiVidual units may not be observed directly, but will affect the overall response of the Clearwater interval.

It is imperative that acquisition parameters be established to ensure repeatability. In a 3-0 survey, there is a choice of shot/receiver geometry between roll along (CDP) or area mode. Often for the sake of cost and time, the area mode is utilized. Processing the data must consider ray path differences between these geometries which can affect velocity analysis, attenuation and in some cases phase distortion. Geophones should be "planted" permanently (cemented in place) and secured for repeated surveys of the same area. It is also important, for inversion, to keep all filtering in the field to a minimum. This is to ensure the maximum bandwidth and the most reliable inversion. The source should be repeatable, either Vibroseis, airgun, shotgun, etc.

Differences in the geophone grid affect the density of data. In many cases adequate coverage can be achieved with half the layout. In this study a 5 x 5 m grid was used although a 10 x 10 m grid would have been sufficient and used only half as many geophones. In any 3-D survey the high density of the grid implies high acquisition, processing and interpretation costs. Any effort to reduce cost without sacrifice of lateral resolution is worthwhile.

When processing data for stratigraphic or reservoir information, a broad bandwidth is essential for adequate resolution of the subtle changes. Scaling and inversion of the data calculates the reflection coefficient series and low frequency addition quantifies the results so that the data can be computer contoured and colored. This allows differentiation between subtle changes in amplitude which may have stratigraphic significance. Often these changes are difficult to recognize without machine-aided displays. Because of thin-bed signal interference it is important to compare filtered logs with the results during the interpretation stage.

Portions of the color depth Seislog displays for one line in the study area are shown in Figures 6 and 7. The data shown on Figure 6 were acquired in 1980, before stimulation of a well located near SP 108. The display window extends for about 450 m from a depth of 270 m at the top to 720 m at the base. The Cretaceous clastic sequence is mainly colored green and the underlying higher-velocity Devonian carbonates are mainly blue colors. The top of the Cretaceous Grand Rapids is marked by oval patterned tape near 330 m, the Clearwater by dashed tape near 470 m, the McMurray by a second ovals tape near 470 m and the Devonian by a wiggle tape near 525 m.

Two other wells are located near the line, west of the area shown in Figure 6. Only one of these wells had sonic information. The other well underwent a short period of stimulation prior to the 1980 survey. The well located near SP 108 on Figures 6 and 7 underwent extensive stimulation between surveys. On this display, the Clearwater could be subdivided into three zones which can be correlated directly to the Cl, C2 and C3 zones on the logs.

A well located near SP 108 is the key well for this study and the discussion will focus on the Seislog display in that vicinity. Figure 6 represents pre-stimulation data and Figure 7 represents conditions shortly after steam stimulation in the well near shotpoint 108. The zone stimulated was the C3 unit of the Clearwater Formation.

At the C3 level, impedance values have decreased on the post stimulation data (Figure 7). The area affected by the steam stimulation has been outlined in red. On the 1981 data, This region is characterized by transit-time values in excess of 450 microseconds/m (low impedance). Colored dark green on the 1980 data (Figure 6), this zone displays values less than 450 microseconds/m (higher impedance). Using this information transit-time values could be converted to equivalent porosity values. Thickness measurements could also be obtained so that (porosity) x (meter) values could be calculated. Processing the data from all of the lines would provide a detailed map of the steam stimulation front.

However, the purpose of this study was only to show that these stimulation fronts can, in fact, be detected, evaluated and mapped with the Seislog techniques (and only one of the three lines "inverted" crossed the stimulation trends). A complication with the study was the different geometry between the 1981 survey and the 1980 survey. This difference changed the raypath distances and altered the thin-bed signal-interference patterns in the two surveys. Thus calibration to well data and transit-time/porosity conversion was hampered.

The inversion of data from this pilot project did demonstrate that inversion is a viable tool for measurement of reservoir stimulation. It is critical that acquisition geometry and source be repeatable. Modern processing sequences can ensure improved resolution. But the processing stream must be identical for the "before" and "after" data. Inversion techniques can quantify the data, which can then be contoured and colored. With sufficient sonic and density information from wells, filtered to the frequency content of the seismic data, calibrations can be made to enable facies and reservoir determinations. This leads to the identification of low- velocity anomalies that are related to the stimulation front. This information can be used to map the effectiVeness of a stimulation project and optimize the placement of injection and producer wells.

I would like to thank AOSTRA for obtaining permission to use this data in this presentation.

Figure 1
Location Map

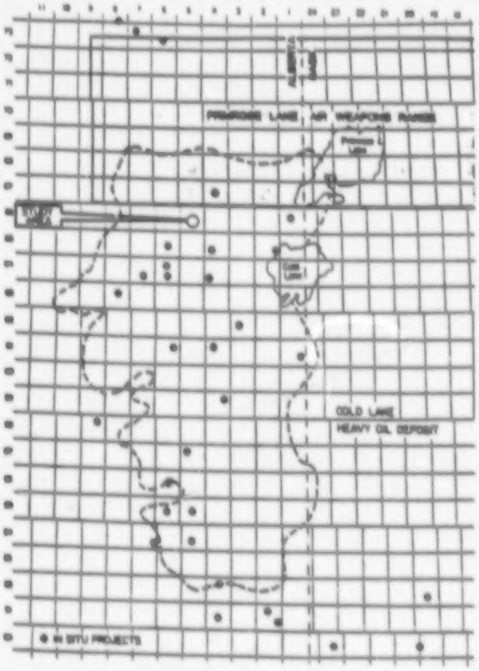

PRIMROSE LAKE AIR WEAPONS RANGE
COLD LAKE
HEAVY OIL DEPOSIT
● IN SITU PROJECTS

Figure 2
Type Log Lake Type

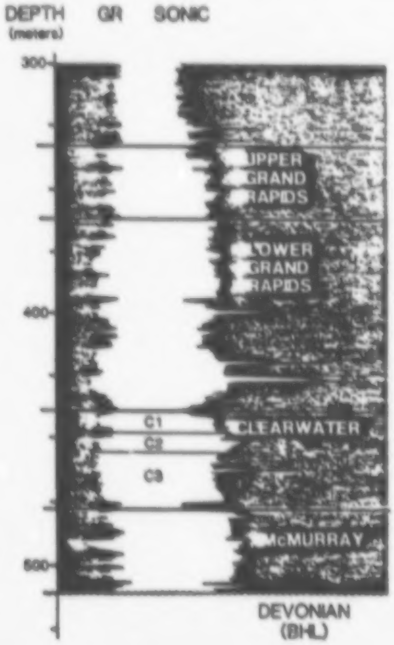


Figure 3
Forward Model

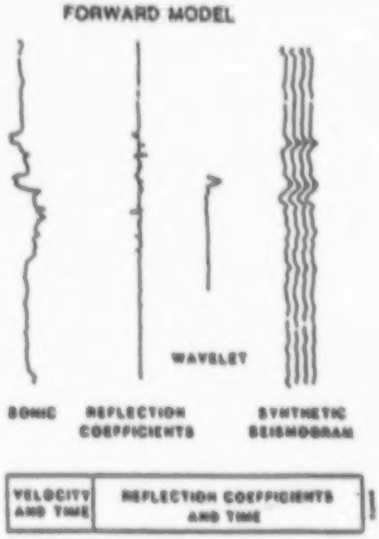

FORWARD MODEL
WAVELET
SONIC
REFLECTION COEFFICIENTS
SYNTHETIC SEISMOGRAM
VELOCITY AND TIME
REFLECTION COEFFICIENTS AND TIME

Figure 4
Inverse Model

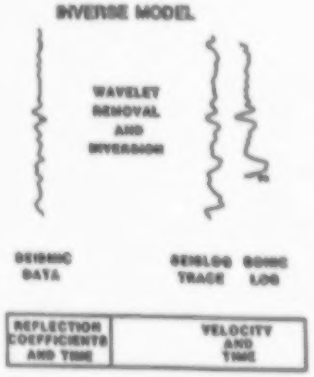
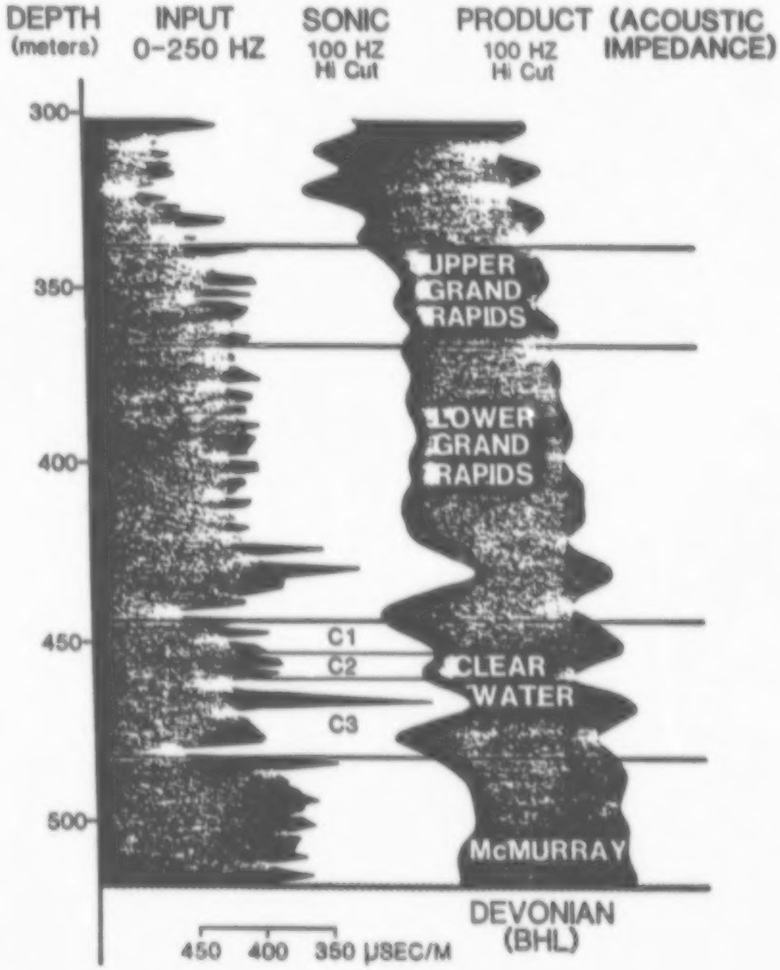

INVERSE MODEL
WAVELET REMOVAL AND INVERSION
SEISMIC DATA
SEISLOG TRACE
SONIC LOG
REFLECTION COEFFICIENTS AND TIME
VELOCITY AND TIME

Figure 4 In the inverse model approximations of borehole sonic logs are constructed from seismic data after appropriate wavelet removal. These logs can be correlated with borehole sonic logs that have comparable bandwidth.

Figure 5
Filtered Sonic and Product Logs



PLOTLOG DISPLAYS
(FILTERED SONIC)

Figure 6
Seislog Before Stimulation

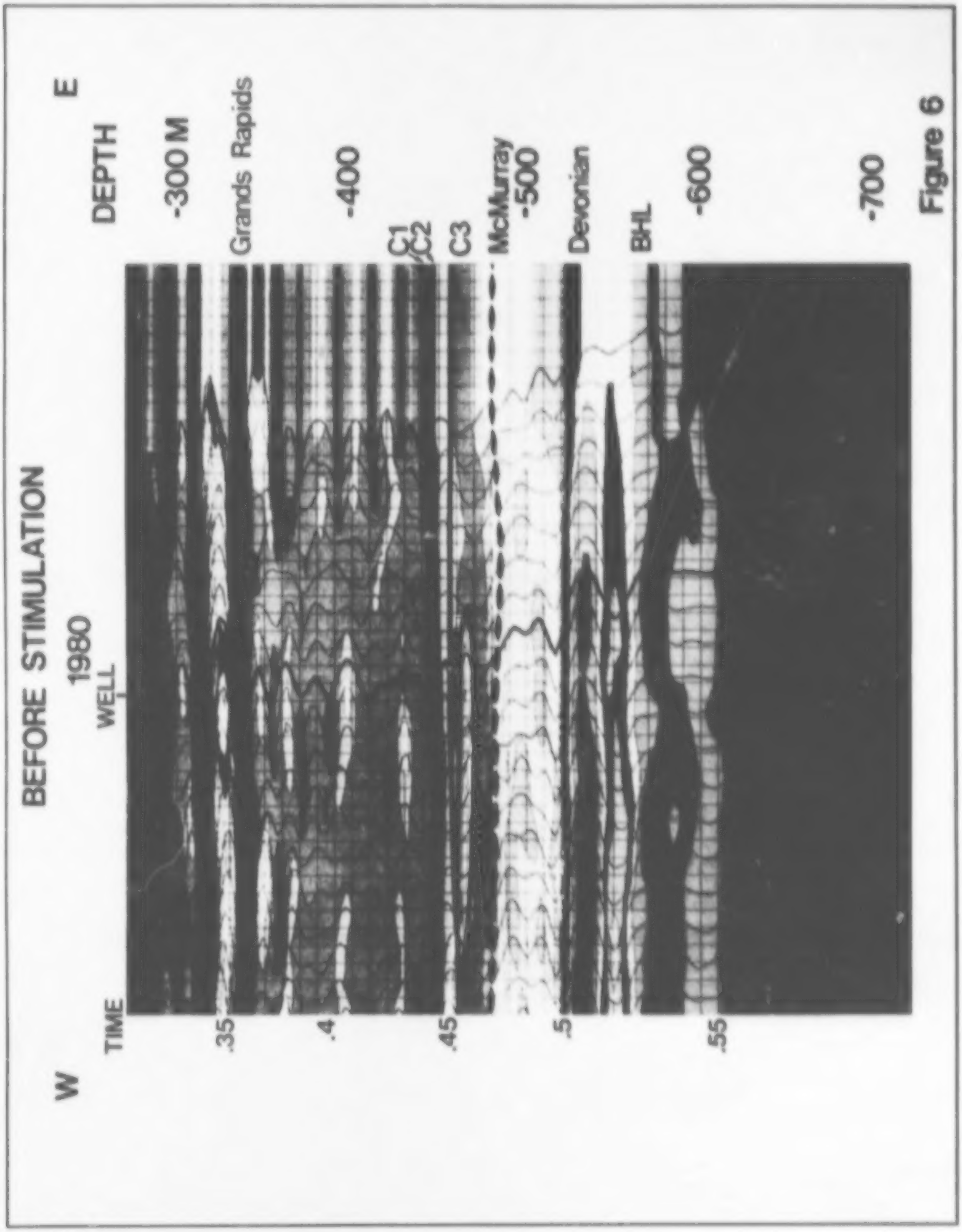
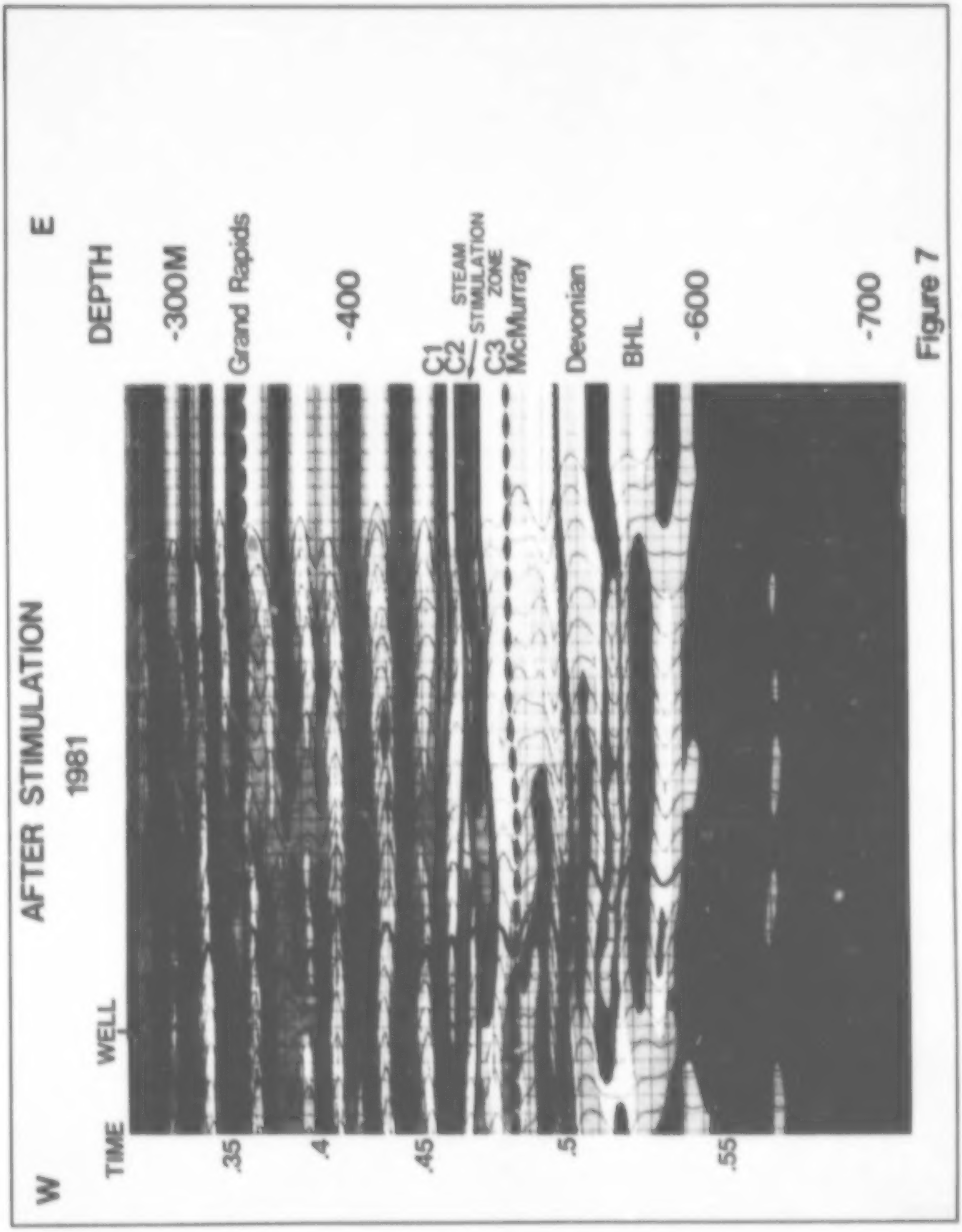


Figure 7
Seislog After Stimulation



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SURFACE FACILITIES DESIGN-CENTRAL PLANT

R.G. Holcek
Delta Projects Inc.

1. INTRODUCTION

The success of surface facility design for central plant commercial scale heavy oil facilities in Alberta, Canada is dependent upon efficient and effective designs for re-use of produced water for steam generation and efficient heavy oil treating system designs.

An important first step in re-use of produced water is the removal of oil from the produced water. Likewise, heavy oil treating systems are essentially the removal of water from crude oil. In concept, both of these processes are simply the separation of oil and water by gravity. However, when processing heavy oil, this is not an easy task due to the nature of heavy oil. This paper will discuss design aspects for the separation of produced water and heavy oil for these processes in an efficient and effective manner.

2. RODUCE WATER TREATMENT FOR RE-USE: OIL REMOVAL

Re-use of produced water for steam generation in in situ heavy oil recovery projects require that essentially all of the oil be removed from the produced water stream. Otherwise, the performance of downstream processes such as lime softening and ion exchange softening will be severely affected. In addition, high concentrations of oil in steam generator feedwater can lead to coke deposits in steam generator tubes and eventual tube failures. Special considerations in the design of the process and equipment for produced water oil removal must be made in order to ensure trouble free operation in the re-use of produced water.

A schematic for a typical produced water deoiling system is shown in Figure 1. Design considerations and functions of each of the following main items of equipment in the process will be briefly discussed.

- *Surge tank*
- *Skim tank*
- *Induced Gas Flotation (IGF) Unit*
- *Fine Oil Removal Systems*

2.1 Surge Tank

The two major functions of the surge tank are to provide:

- *surge capacity for the deoiling system in the event of large slugs of produced water, and*
- *storage capacity for the deoiling system in the event of a malfunction in the deoiling process.*

The operational success of the deoiling system is dependent upon "steady state" flow of produced water to ensure the highest possible oil removal efficiency. Since the flow of produced liquids to the plant usually comes in slugs, surge capacity for the deoiling system must be provided. If a large slug of liquid is allowed to enter the skim tank without any "dampening", large amounts of oil could be carried over into downstream deoiling equipment. Induced gas flotation units require precise level control to function properly and any sudden surge in produced water flow could adversely affect their operation. These upsets could lead to plugging of the fine oil removal filters, since they are designed for removal of only small amounts of oil. Even worse, oil could be carried over to the water softening equipment or to the steam generators.

The surge tank should be provided with adequate storage capacity in the event that it is necessary to shut the deoiling process down due to a malfunction. In this way, operation of the production treatment and steam generation systems can continue while the problems with the deoiling system are being rectified.

2.2 Skim Tank

The skim tank is a cylindrical separator which uses simple gravity separation for gross oil and suspended solids removal. Gravity separation usually needs considerable time, thus requiring large tanks.(1) Typical residence times required are approximately six hours; under favourable operating conditions the oil concentration in the effluent water will be between 40-50 ppm.

The rise rate for the separating oil droplets is very slow. Therefore, it is of fundamental importance to provide a quiet zone in skim tank designs to ensure proper oil-water separation. Any sudden surges or slugs in the flow to the skim tank will upset this separation process. Other design features that should be included are the use of large diameter tanks to maximize oil-water interface and a baffle system to eliminate short-circuiting within the tank.

The skim tanks are normally fabricated from standard storage tanks, and have a central entrance and a peripheral effluent discharge. One design for a skim tank has been adapted from a horizontal basin design (from the API manual) to a vertical cylindrical vessel (see Figure 2).

■ 2.3 Induced Gas Flotation Units

The flotation process operates on the principle of increasing the density difference between the oil and water by attaching gas bubbles to the oil droplets. The combined oil-gas droplet also has a larger diameter which further increases the rising velocity. Both of these factors result in dramatically decreasing the oil/water separation time.

In the induced gas flotation (IGF) unit, a fine dispersion of gas bubbles is achieved by mechanically mixing the gas into the oily water by means of a mechanical rotor. A high concentration of gas bubbles is desirable since it increases oil recovery. The froth resulting from the gas bubbling through the produced water stream is allowed to separate at the top of the unit and is skimmed off. Thus, a high percentage of the oil is removed. A schematic for a typical IGF unit is shown in Figure 3.

Chemical flotation aids such as organic polymers and polyelectrolytes enhance the separation efficiency by mechanisms such as flocculation, demulsification and charge neutralization. Since each produced water stream contains different surface active agents, different flotation chemical aids will usually be required. Tests with the various chemicals will need to be carried out in order to determine the most suitable chemical or combination of chemicals.

The design of the rotor-type induced gas flotation unit is based upon four cells, so that the produced water stream is contacted with the gas bubbles four separate times. Vendor design criteria is based upon a residence time of one minute per cell. However, actual operating experience in the heavy oil industry indicates that it is necessary to derate the units by 50% to achieve good performance (i.e., use 2 minutes residence time per cell.)

■ 2.4 Fine Oil Removal Systems

There are basically two systems for fine oil removal - coalescers and deep bed filters. Both of these systems contain a bed of granular media (predominately sand) and are capable of reducing both the oil and solids concentration to less than 1 ppm in the produced water.

Coalescers

The coalescer media must be capable of becoming oil-wet. As the produced water flows through the bed, the tiny oil droplets and solids in the water attach themselves to the oil film that surround the media and are removed from water stream. After the coalescing media becomes clogged with oil and solids, these substances are removed in the cleaning cycle.

Granular coalescing media has the following three characteristics that make it suitable for removal of fine oil from water:(3)

- ☐ *The media bed has a very high ratio of surface area of coalescing media per unit volume. This makes it nearly impossible for an oil droplet to escape the bed without touching a coalescing oil film.*
- ☐ *The flow path through the bed is continually altered so as to create multiple collisions between the oil droplets and the coalescing oil film.*
- ☐ *The coalescing media is easily cleaned of the suspended solids and oily crud. It has the ability to withstand a vigorous cleaning cycle that is necessary to remove these substances.*

In coalescers, the produced water flows up through the bed. As previously mentioned, as the water passes through the media, it is attached to the oil film surrounding the media. This oil film continues to trap oil droplets until the film becomes too large for the media to hold. These larger droplets then break free and float to the top of the coalescer vessel, where are separated from the water stream. While this is happening, the suspended solids are being filtered out from the produced water stream by the media. When the media becomes sufficiently clogged, it must be backwashed for cleaning.

Deep Bed Filters

In deep bed filters on the other hand, the produced water flows downflow through the bed. The oil droplets, that attach themselves to the oil film surrounding the media, are not allowed to float free, but are trapped in the media bed with the suspended solids. When the bed becomes clogged, it is backwashed to remove the trapped oil and solids.

When cleaning the media bed in coalescer or deep bed filters, it is usually not sufficient just to backwash with a high flow rate of water. The mixed cruds of solids and oil filtered from the produced water tend to stick to the media. The most effective way to remove these oily cruds is to backwash with a simultaneous flow of gas and water. This causes the media to vibrate rapidly and to scrub against itself, thus effectively removing the solids and oil collected in the media. The size of the sand grains and depth of the sand bed are variables that can be adapted to each application. However, some basic criteria apply for produced water systems.(3)

❑ *for coalescers, the sand grains used are fairly large, normally 1.3 mm - 1.6 mm effective size. The bed depth is relatively shallow, 1200 - 1400 mm.*

❑ *for deep bed filters, the sand grains are smaller, normally 0.8 mm - 1.3 mm effective size. The bed depth is dependant upon the amount of solids, but is generally between 1200 - 2000 mm.*

3. PRODUCED FLUIDS TREATMENT (OIL AND WATER SEPARATION)

As previously mentioned, the removal of water from oil in a produced fluids treating system is separation of oil and water by gravity. Although this process is fairly straight forward when dealing with conventional crude, it is much more difficult when dealing with heavy oil. This is because heavy oil has a specific gravity close to that of water and has a very high viscosity.

Removal of the free water (approximately 95% of the total) is relatively simple.(4) However, removal of the remaining water is not so easy. Stokes Law provides us with the fundamental equation of how the water is separated from the oil. The relationship of how the water separates from the oil is as follows:

Rate of settling = $K\,(pw-po)\,g\,d^2/n$

Where

K = constant of system

pw= density of water phase

po = density of oil phase

g = gravity factor

d = diameter of droplet

n = viscosity of oil

Additional means that are used to speed up this separation process in a heavy oil treating system that will be briefly discussed are as follows:

❑ *Chemical Addition*

❑ *Heat*

❑ *Mechanical and Electrostatic Treaters*

❑ *Diluent Addition*

Before discussing each of these aspects that relate to the separation of oil from water, it may be useful to review the overall process scheme. A schematic of this process is shown in Figure 4. The inlet production first enters an inlet degasser vessel where the produced gas is separated out. The inlet degasser can also be used as a "slug catcher". If large slugs of liquids are expected, a separate "slug catcher" vessel may be required. The produced fluids are cooled (or heated) before entering a free water knockout (FWKO) vessel. The FWKO vessel is usually a mechanical treater with special internals and is used to separate out free water. The produced fluid, which normally contain between 2% - 5% water, is then sent to an electrostatic treater where the remainder of the water is removed. Depending upon the specific gravity of the heavy oil, diluent can also be added upstream of the treater to improve the separation characteristics of water from oil. The electrostatic treater uses electrical energy to help coalesce the water particles so they can be more easily separated. A typical specification for the salable oil product from this treater is 0.5% BS&W (where BS&W refers to Bottoms, Sediment and Water).

■ 3.1 Chemical Addition

One difficulty associated with oil and water separation are the formation of oil/water emulsions. Emulsions are a mixture of oil and water, with the water being dispersed as droplets in the oil phase. These oil/water emulsions are caused by the intimate contact and turbulence of the oil with the water in the production of crude oil and are stabilized by naturally occurring surface active materials. These materials include such compounds as asphaltenes, paraffins, metallic salts, silts, clays, etc. many others.

In order to properly separate the water from the oil, it is first necessary to break these emulsions. Chemicals, known as demulsifiers, are added to the oil production to help break these emulsions by displacing or weakening the emulsifier envelope that surrounds the water droplets. Properties that the demulsifiers must have to be effective are:(5)

- *Strong attraction to oil-water interface, where the emulsion usually exists.*
- *Flocculation. It must be able to bring the water droplets in the emulsion together.*
- *Coalescence. After bringing the water droplets together, it must be able to unite these droplets so they will settle out.*
- *Solids Wetting. It must have the ability to attach itself to any solids present, so that these solids are attracted to the water phase and are removed with the water.*

It is advantageous to add the demulsifiers to the production as far upstream as possible to give the demulsifier maximum time to work. Generally, the demulsifier should be added to the production flowline near the wellhead facilities. However, additional chemical injection points should also be provided in the production treating unit.

Since the nature of the emulsions formed in each production system are different, there is no single best chemical. Each system must be evaluated with respect to the parameters of the produced fluids before the demulsifier chemical can be selected. Specialty companies who are skilled in this field can be contacted for their services.

3.2 Heat

Since heavy oils are usually produced by high pressure steam injection, their inlet temperatures are normally hot (between 100-150°C) and they will require no further heating. If the temperature of the heavy oil is below 100°C, some heating may be required. Heat aids in the treatment of heavy oil since it will:

- *Substantially reduce the viscosity of the heavy oil. This dramatically decreases the settling time of water droplets. (See Stokes Law).*
- *Add energy to the system, creating thermal currents and water droplet movement. This increases the number of collisions between the water droplets and therefore helps coalesce these droplets.*

However, heat cannot be used indiscriminately for treating heavy oils. As the production fluids are heated, the specific gravity difference between heavy oil and water actually decreases. In fact, if the production fluids are heated too high, the water can actually become lighter heavy oil!

In addition, too much heat also causes vaporization of light components in heavy oil. As a result, the API gravity of the heavy oil increases and there will also be some loss of oil product, unless a vapour recovery system is provided to recover these light components. However, even if a vapour recovery system is installed, it will not be possible to recover all of the light components vaporized.

3.3 Mechanical and Electrostatic Treaters

Mechanical and electrostatic treaters work on the principle of causing the small water droplets in the oil to come together to form larger droplets. When these droplets become large enough, they will then settle out by gravity. The settling time for the water droplets decreases very rapidly as their size increases (by the square of the diameter of the droplet.) The use of mechanical or electrostatic treaters speeds the settling time for the water droplets considerably, allowing much smaller vessels to be used.

Mechanical treaters provide large surface area of specially designed internals such as "hay sections" on which water droplets can collect and coalesce to become larger droplets. The "hay sections" are essentially a fibrous media that mechanically coalesces the tiny water droplets. Plugging of this type of mechanical coalescers with sediment, salt, etc. can be a major problem. These types of mechanical coalescers must be periodically replaced.

A design by one vendor that has proven to be satisfactory uses a different principle for mechanical treaters (see Figure 5). Louvered plates are placed in the vessel to effect coalescence and insure uniform distribution of the flow throughout the vessel. The louvers are designed to change the direction of the water as it impacts against the plate. The cutting edges of the louvers break the oil film around the water droplets, allowing them to coalesce and settle.

Electrostatic treaters use electricity to coalesce the tiny water droplets into larger droplets. Electrodes are placed in the vessel to produce an electric field. When the oil enters the electric field, the electrical charges that exist in the water droplet are separated, with the positive charges being located at one end and the negative charges at the other end. The water droplets are then attracted to each other and coalesce to form larger and larger droplets, until they eventually settle out. Designs for electrostatic treaters include those that utilize an AC field and others that utilize a combination of both an AC field and DC field.

When designing a mechanical or electrostatic treating system, it is important to ensure a quiet settling zone for the water droplets since turbulence increases the settling time considerably. The production to the plant generally comes in slugs; it is therefore important to provide a slug catcher for these slugs. The slug catcher dampens the effect of the slugs coming into the plant, and then regulates the production flow to the treating systems so that separation of the oil and water will be done in a quiet and efficient manner.

■ 3.4 Diluent

Since heavy oils are generally too viscous to pump through a conventional pipeline, a diluent can be added to reduce its viscosity so that it can be more easily pumped. A diluent is any miscible fluid that is lighter than heavy oil. Examples of diluents are stabilized condensates associated with natural gas production (pentanes, hexanes, heptanes, etc.) or naphtha which is a light refinery stream.

In systems where diluent is used to transport heavy oil, it is advantageous to add the diluent upstream of the treaters. This is because diluent improves the separation characteristics of water from oil. When diluent is added, the specific gravity difference between oil and water is increased and oil also becomes less viscous. This greatly improves the ability of water to separate out from oil, allowing much smaller vessels to be used. This system works well if a diluent is available for treating. All of the large commercial projects in Canada use diluent in the treating process.

Care must be taken in the design when adding diluent to a heavy oil treating process in order to minimize its losses and consumption. This is because diluent is typically more expensive than heavy oil and excess use of it could significantly increase the operating costs. Delta Projects Inc. has proprietary designs which can minimize diluent losses and consumption.

4. CONCLUSION

Oil removal from produced water, and the removal of water from oil are two important process steps in the design of commercial scale heavy oil projects.

To ensure trouble free operation in the re-use of produced water for steam generation, all of the oil must be essentially removed from the produced water. Special consideration in the design of the equipment for the oil removal process (surge tank, skim tank, induced gas flotation unit, and fine oil removal filters) must be made so that this process is carried out in an effective and efficient manner.

The removal of water from oil is basically a gravity separation process, with this process being speeded up by chemical addition to break emulsions, heat to reduce viscosity, diluent addition to reduce the specific gravity difference and viscosity, and the use of treaters to coalesce the small droplets of water. All of these elements must be applied in an efficient manner to minimize costs and conserve energy in order to get the job done as efficiently as possible.

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- 2. Stires, Joe, "Design of a High-Rate, High Volume Oil/Water Separator", JPT Nov., 1982.
- 3. Bowser, Patrick, "Principles of Coalescense and Their Application to Produced Water Treatment", Canadian Heavy Oil Association Quarterly Meeting, April 30, 1986.
- 4. Burris, D.R., "Dual Polarity Oil Dehydration", Petroleum Engineer, August, 1977.
- 5. "Dehydration/Desalting of Crude Oil - Training Program", Petrolite Corporation, 1983.

Figure 1
Produced Water Oil Removal Schematic

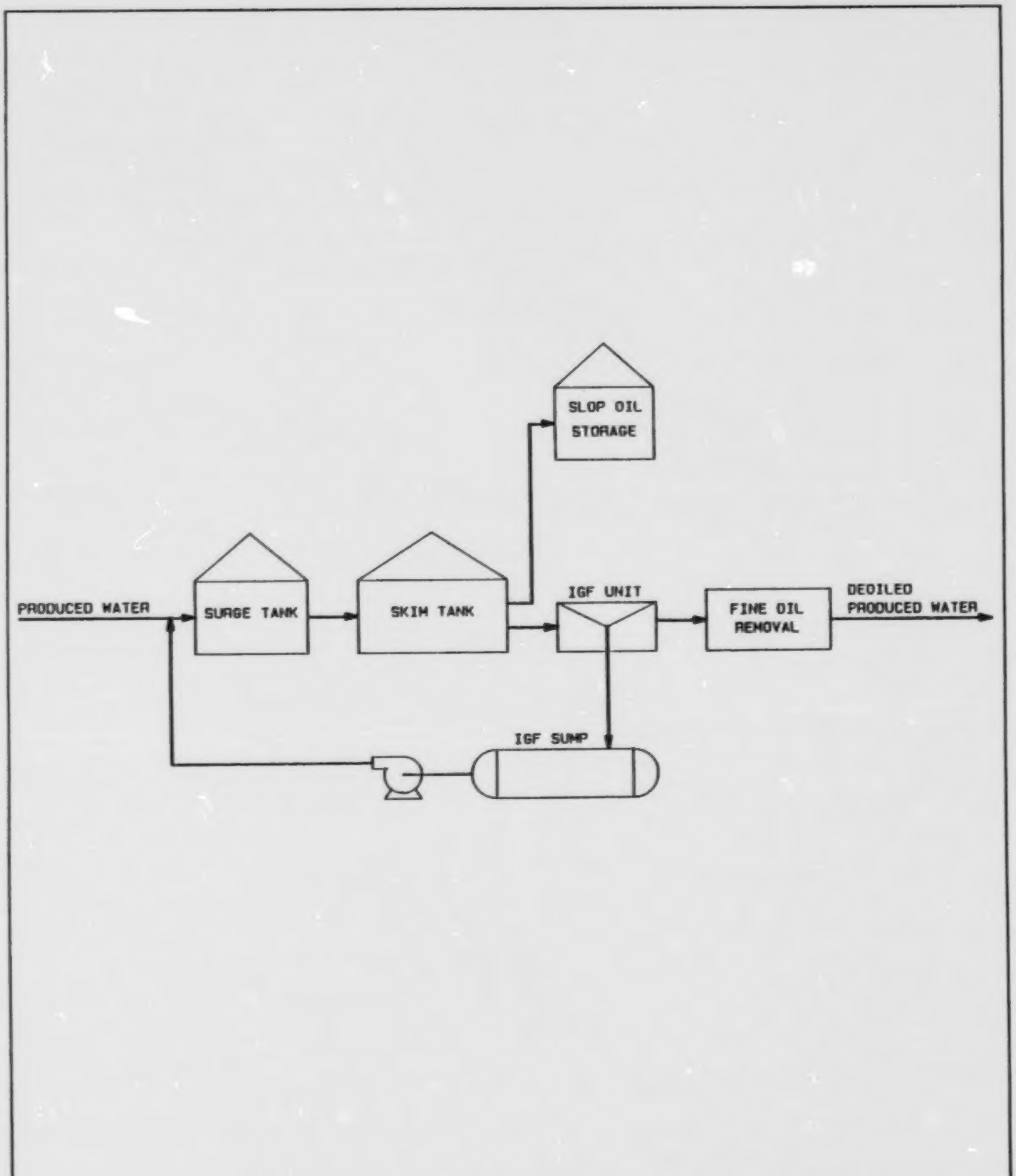

SLOP OIL
STORAGE
PRODUCED WATER
SURGE TANK
SKIM TANK
IGF UNIT
FINE OIL
REMOVAL
DEOILED
PRODUCED WATER
IGF SUMP

Figure 2
Skim Tank Schematic

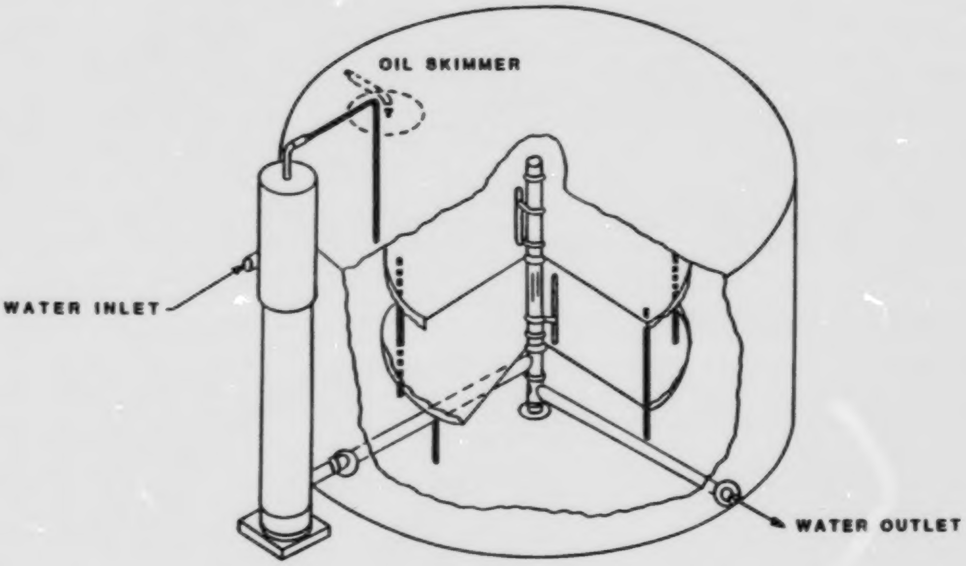

OIL SKIMMER
WATER INLET
WATER OUTLET

Figure 3
IGF Unit Schematic

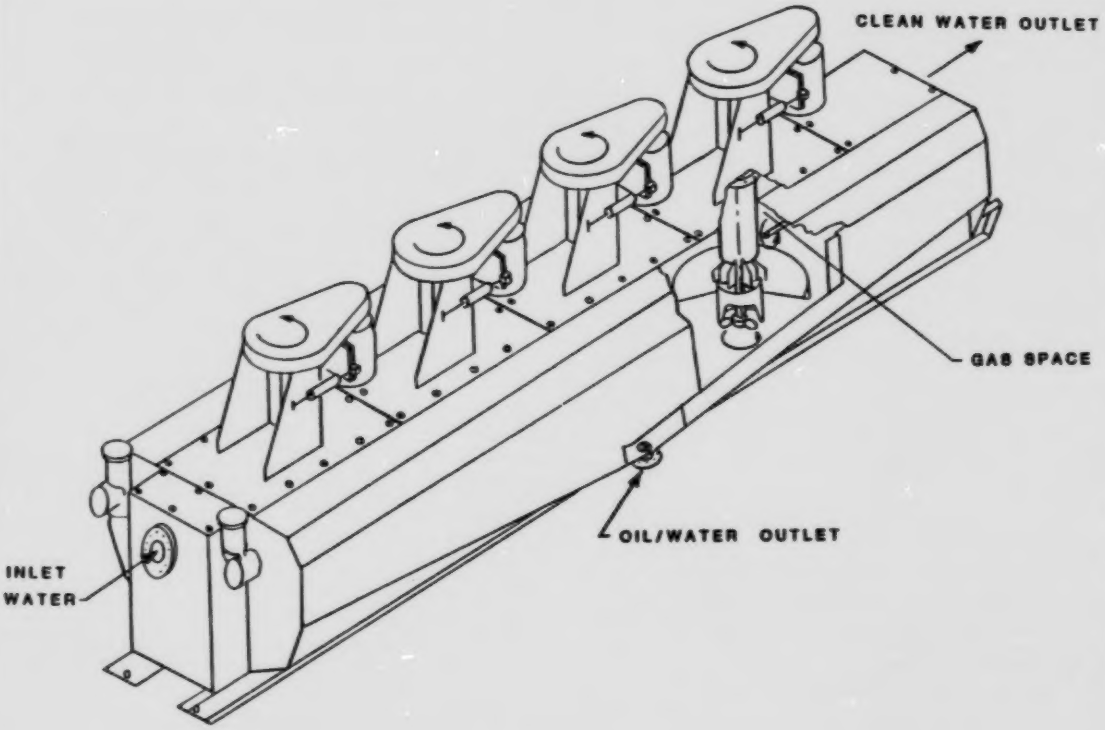

CLEAN WATER OUTLET
GAS SPACE
OIL/WATER OUTLET
INLET WATER

Figure 4
Produced Fluids Treatment Schematic

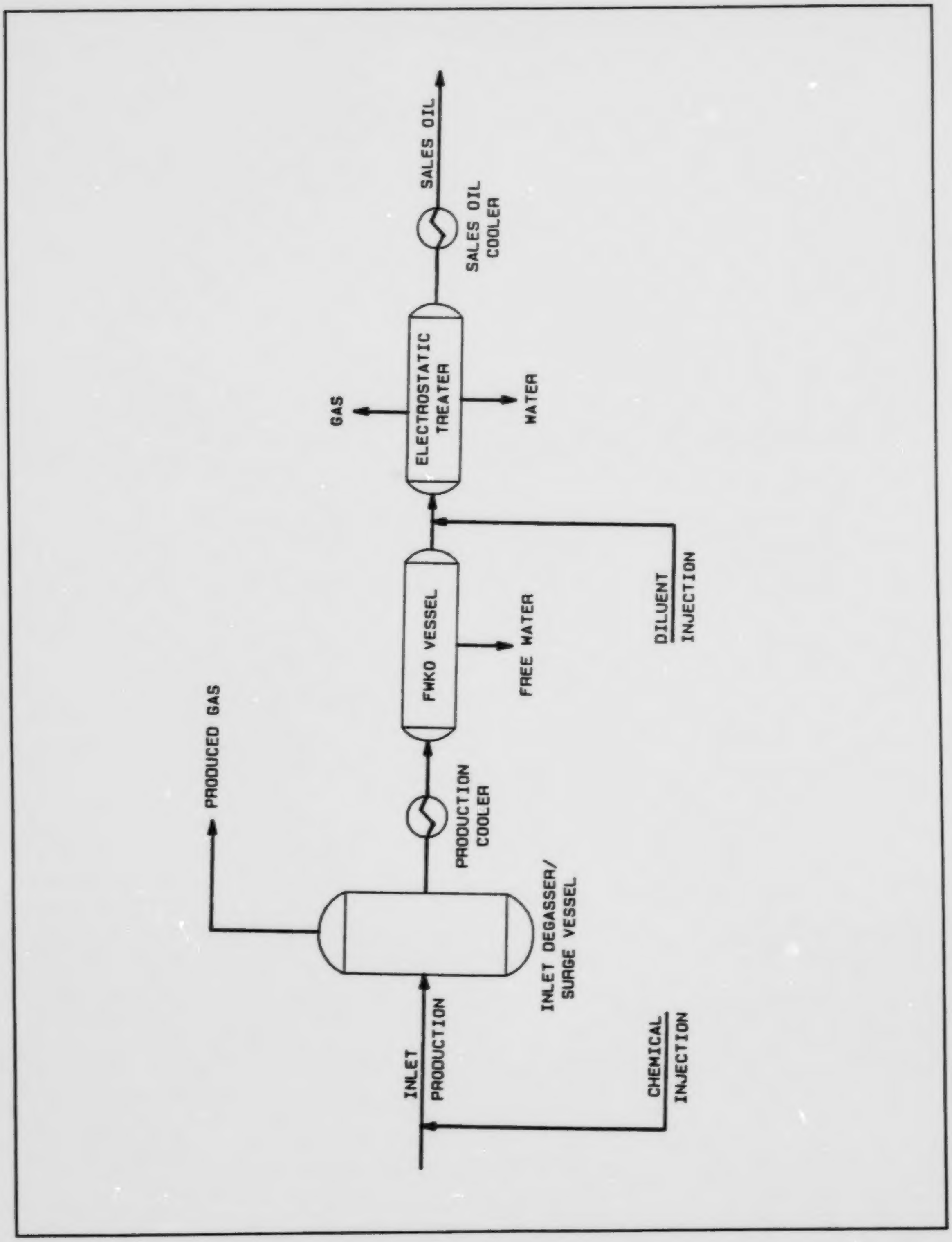
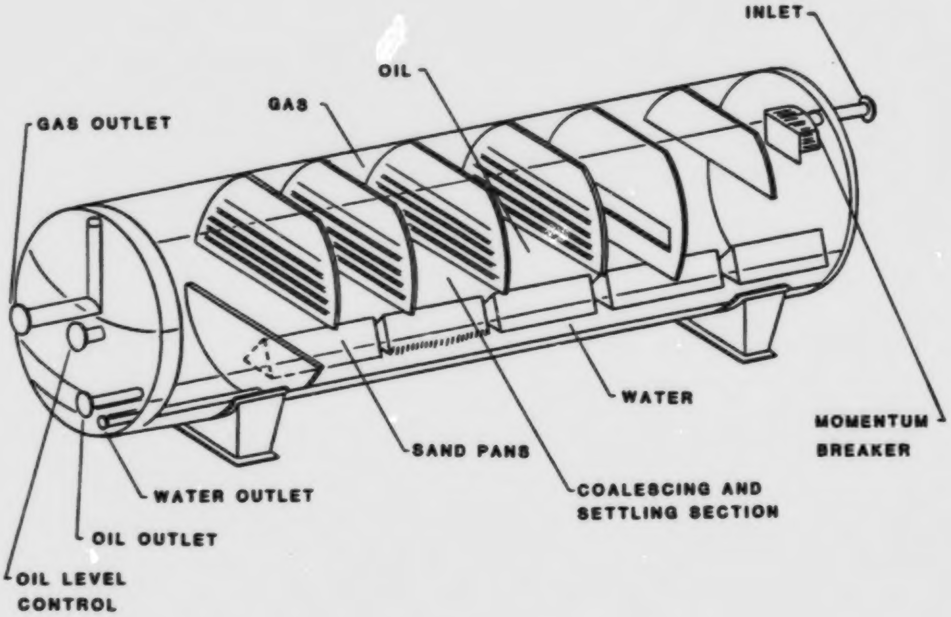

INLET PRODUCTION
CHEMICAL INJECTION
INLET DEGASSER/ SURGE VESSEL
PRODUCED GAS
PRODUCTION COOLER
FWKO VESSEL
FREE WATER
DILUENT INJECTION
ELECTROSTATIC TREATER
GAS
WATER
SALES OIL COOLER
SALES OIL

Figure 5
Mechanical Treater Schematic


INLET
OIL
GAS
GAS OUTLET
WATER
MOMENTUM BREAKER
SAND PANS
COALESCING AND SETTLING SECTION
WATER OUTLET
OIL OUTLET
OIL LEVEL CONTROL

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HEAVY OIL GATHERING AND TRANSPORTATION TECHNOLOGY FOR GAOSHENG OILFIELD

Chen Yongsui
Design Company, Liaohe Oilfield

ABSTRACT

This article discusses the experience and problems associated with the application of the technology for gathering and transportation of heavy crude blended with surface active water at the Liaohe Gaosheng oil field during its early production days. The article also presents laboratory experiments and field tests to demonstrate the effectiveness of viscosity reduction by blending with light oil. Since results from these tests were very encouraging, the light oil blending process was implemented throughout the field replacing the water blending process. It becomes part of an integrated system closely interrelated with recovery process and heavy oil upgrading. The article also touches upon the design philosophy, economic benefit and experiences with the heavy oil gathering and transportation technology.

INTRODUCTION

Gaosheng heavy oil is viscous and its specific gravity is high, as shown in Table 1. By blending oil with water containing surfactants, we were able to reduce the apparent viscosity to 2000 cp at 50° C, but there were other complications associated with the water blending method such as:

- ☐ *1) excess water in the blending operation would result in unstable emulsion and*
- ☐ *2) inconsistent viscosity reduction effectiveness. This method often upsets operations of oil dehydration, water treatment, pumping and instrumentation.*

EXPERIMENTS TO REDUCE VISCOSITY BY LIGHT OIL BLENDING

Because the water blending method was problematic, experiments were carried out in the laboratory and on site to develop an alternative technology. Laboratory results show that significant viscosity reduction can be achieved by blending heavy oil with light oil, and when the viscosity indexes of heavy and light oils are close, viscosity of the blend calculated from the following empirical equation is in good agreement with the experimental data,

$$\mathrm{Log}[\mathrm{Log}(\mu_m))] = \sum_{i}^{n} X_i \cdot [\mathrm{Log}(\mathrm{Log}(\mu_i)]] \tag{1}$$

Where μ_m is viscosity of the blend in centipoise and μ_i is viscosity of heavy or light oil, and X_i is blending ratio in weight percent of heavy or light oil.

From the experimental results and Equation 1, it is observed that viscosity reduction is greater as a result of blending with either less viscous light oil or more viscous heavy crude when blending ratio is kept constant, as shown in Table 2.

Field tests were carried out at Wells 6-04 and 7-04 of the Huanxiling oilfield. These two wells were shut in at the time due to high viscosity of the oil produced. Viscosities of the oil from these two wells were 8,760 and 6,660 cp measured at 50°C. The test demonstrated that with the injection of light oil, the wells were able to produce at a rate inversely proportional to the viscosity of the injected light oil. On July 14, 1982, modification was made at Gaosheng Gao Well# 7 to replace the water blending process with the light oil blending process. Field test was subsequently carried out by blending light oil of 10.4 to 11.8 centipoise with heavy oil of 2,600 cp at 50° C. Comparison of the production data from the two blending processes given in Tables 3 and 4 indicates a 50% increase in heavy oil production since the introduction of the new process. Also, at a smaller light/heavy oil ratio of 0.65 than the 1.8 water/heavy oil ratio for the old process, the light oil blending process produced 40% less liquid volume, resulting in less friction loss in pipelines, less volume for water treatment and dehydration, and ease of operations of the degassers, dehydration and sand removal units. It is worth pointing out that the data from the field tests are in good agreement with the values calculated from Eqn (1).

Based on the above experimental results, the light oil blending process was implemented throughout the entire Gaosheng oil field.

GAOSHENG INTEGRATED PRODUCTION, TRANSPORTATION AND REFINING OPERATIONS

Gaosheng, an important oilfield at the north of the west slope of Liaohe Basin, is currently producing 2,700-3,000 tons per day with well spacing of 15-18 per square kilometer. Surface facilities include 23 metering/boosting stations, usually located about 350-400 meters from wellheads, and a central processing plant.

Design Philosophy

Light oil blending process for viscosity reduction should be considered as part of an integrated operations including oil recovery, transportation, degassing, oil treatment and metering. Mixing of heavy oil with crudes produced from other parts of the Liaohe Provinces at refineries may not be the best alternative as far as utilization and improvement of the economics of the resources are concerned. A better approach is to treat heavy oil production, transportation and refining as integrated operations. For this reason, the Panjin refinery will be modified to upgrade heavy crude. Instead of using the volatile gasoline fraction, the 170-280 degree C diesel fraction from the refinery is to be recycled to the field and diluted with the heavy oil at 30% by volume so as to bring the viscosity down to about 100 cp. Before the modification of the refinery is completed, light crude with less wax content will be used temporarily as the diluent.

When water blending was replaced by the light oil blending process, surface facilities for the heavy oil gathering and transportation were modified from an open system into a closed system. The design parameters for the closed system are given as follow:

Single Well Production	10-20 Tons/Day
Wellhead Pressure	10 Kg f/cm^2
Pressure at Metering Station	4 Kg f/cm^2
Inlet Pressure, Treatment Plant	2-2.5 Kg f/cm^2
Light Oil Temperature at Wellhead	60 C^o
Light Oil Pressure at Wellhead	15-25 kg f/cm^2
Diesel/Heavy Oil Ratio	0.3

If light oil is used in the blending process, the ratio can be adjusted with the viscosity of the light oil.

To meet various field conditions, the process must be flexible such that light oil can be injected either downhole or at the surface, or no injection at all when heavy oil can be gathered and transported without viscosity reduction.

Equipment must be selected according to heavy oil characteristics. For example, high capacity positive displacement pumps rather than the centrifugal pumps should be used at the metering/boosting station. Each wellhead should be equipped with a control valve for controlling the flow of light oil. At the central plant, a 2,000 cubic meter vessel is to be used as a gravity settler and electrical precipitator for dehydration process. Also, pipelines should be large enough to minimize wellhead pressure and they must be insulated with polyester foam to reduce heat loss.

Gaosheng Heavy Oil Gathering and Transportation System

Surface facilities at Gaosheng oil field consists of metering/boosting stations, block stations, a central processing plant and metering systems which are capable of measuring fluids from an individual wellhead, a metering/boosting station and a block station. (See the attached process flow diagram). Diesel oil from the refinery is recycled to the field for heavy oil transportation (light oil with low wax content is used before the refinery is modified to produce diesel oil). At a wellhead, light oil from refinery (E) is heated in a heat exchanger (2) and injected through casing to bottomhole where it is mixed with heavy oil and pumped to the surface with a sucker rod pump. Produced fluids from a wellhead pass through the heat exchanger (2) to a metering manifold in the metering/boosting station. From the manifold, fluids from a single well are heated in a metering heater(4) before entering a degasser (5). At the degasser, gas and liquids are metered before the gas is sent to the gas lines and the liquids are combined with produced fluids from other wellheads in a separator (6). The gas from the separator is metered and gathered in the gas lines (III) while the liquids is metered and pumped to a block station. Produced liquids from several metering/boosting stations are combined and measured in the block station before entering the central processing plant (D). In the plant, fluids from various blocks stations are combined at manifold (11); they are then heated in a heater (12) and treated for oil water separation in a gravity settler (13). Oil from the settler is further treated in a heater (15) and an electrical precipitator (16), and stored in a tank (17). From the tank farm, oil is heated again , metered and pumped to the Refinery (E). Meanwhile, produced water is treated to specification for disposal.

Diesel oil from the refinery is metered and stored in a storage tank (21) from which the oil is distributed to tank(24) in various block stations and then to a heating vessel (28) at various metering/ boosting stations. It is then distributed to wellheads through a manifold(30) and a flow control valve. According to different conditions at wellheads, diesel(or light) oil can either be injected to bottomhole or at the surface; or sometimes no injection is required if heavy oil can flow without viscosity reduction.

Light oil is being used currently at the field until modification at the refinery is complete. Once diesel oil is available from the refinery, heaters (23) and (26), and vessel (28) shown in the flow diagram become redundant and will not be used.

■ Production at Gaosheng Oil Field

Total 1986 heavy oil production from the Gaosheng oil field was one million tons. For the 37 wells operated under close production system, wellhead pressure varied from 7 to 11 kg f/cm^2, with an average pressure at 8.25 kg f/cm^2. For the remaining wells under open production system, wellhead pressure was lower and they required less light oil for blending . Overall Light/heavy ratio dropped to 0.28 by the end of 1986 and as a result, viscosity of the blend increased from 187.6 cp (50^o C) at the beginning of the year to 481.2 cp at year end. Foaming was a serious problem but was effectively overcome by the use of trimethyl silicate. Also, because of the better product quality achieved with the injection of 50 ppm of emulsion breaker AP8051 in the oil dehydration process, the difference in volume between oil produced and oil sold was reduced to 1.5%

■ The Affects of Light Oil Blending at Gaosheng

By diluting heavy oil with 30% diesel oil, the viscosity is effectively reduced from 2000-3000 cp range to 100 cp(50^o C) and specific gravity also becomes smaller. The accompanying reduction in friction loss and static pressure in production tubing revive some of the dead wells or low production wells (0.5-8 tons/day). The blending improves degasser and dehydrator operations, produces better oil quality (0.5% water content) and reduces the difference between oil produced and oil sold from the previous 30-60 % when the water process was used to the current 1.5%. It also improves working conditions of pipelines, instruments and pumps, and reduces the repair frequency of the multi-stage centrifugal pumps from once a week to once in six months. The process reduces electricity consumption by 50% and fuel by 30% at the metering/boosting station and improves the ease of operations of the stations.

Upgrading and refining heavy oil at Gaosheng will bring in better returns. For example, the market value of upgraded products from 1 million tons of heavy oil is 420 million yuan as compared to the 120 million yuan from the heavy oil diluted with crude oil from other oil fields in Liaohe.

CONCLUSION

Heavy oil gathering and transportation should be considered in conjunction with overall heavy oil utilization, production rate, oil properties, availability of light oil and capability of local refineries. The gathering system should be operated closely with oil production. For example, during the early cyclic steam stimulation when production rate and fluid temperature are high, and where no high temperature surface pipeline is available, it is suggested that the hot fluids be cooled with an air cooler or a skid mounted vessel below 90 degree C before it is transported in a buried pipeline. In the design and construction of buried pipelines, thermal stress and pipeline deformation should be considered to avoid any pipeline damage.

To stabilize oil production, gas should be separated from produced liquids after heating at the metering/boosting stations and transported separately to the central plant where produced fluids are further degassed at atmospheric pressure in two stages prior to the settler tank. In the central processing plant, gas is recovered with compressors. The degassers at the central plant should be equipped to deal with foaming and sanding problems. Also, work to screen emulsion breakers should be conducted to improve oil dehydration process.

REFERENCES

■ 1) Chen Yong-Sui, Ma Hua-fu,"Equation for Viscosity of Heavy/Light Oil Blend", Oilfield Surface Engineering, Vol. 2, No 4, Nov., 1983.

Table 1
Properties of Heavy Oil from Goasheng

	Range	Normal
Relative Specific Gravity	0.93 - 0.97	0.94 - 0.9
Viscosity at 50^{o}, cp	400 - 8000	2000 - 3000
Resin Content, %	31 - 40	34 - 36
Asphaltent Content, %	5 - 11	6 - 8
Asphaltent + Resin, %	33 - 50	40 - 46
Wax Content, %	3.4 - 6.2	3.5 - 5.0
Pour Point, ^{o}C	9.5 - 26	4 - 9
Sulphur Content, %	0.49 - 0.64	0.5 - 0.6

Table 2
Viscosity of the Heavy Oil and Light Oil Blend

	Blend #1	Blend #2
Light Oil Viscosity, cp	9.0	1.6
Heavy Oil Viscosity, cp	5850	5850
Heavy/Light Oil by Weight	1	4
Measured Viscosity at 50^{o}C, cp	79	128
Calculated Viscosity at 50^{o}C, cp	78.7	126.7
% Difference	0.4	1.0

Note: Heavy oil from Jin Well#45.
Light oil from Xing #2 CPU for Blend #1; from Ma Well#64 for Blend #2

Table 3
Comparison of Monthly Production from the Two Processes

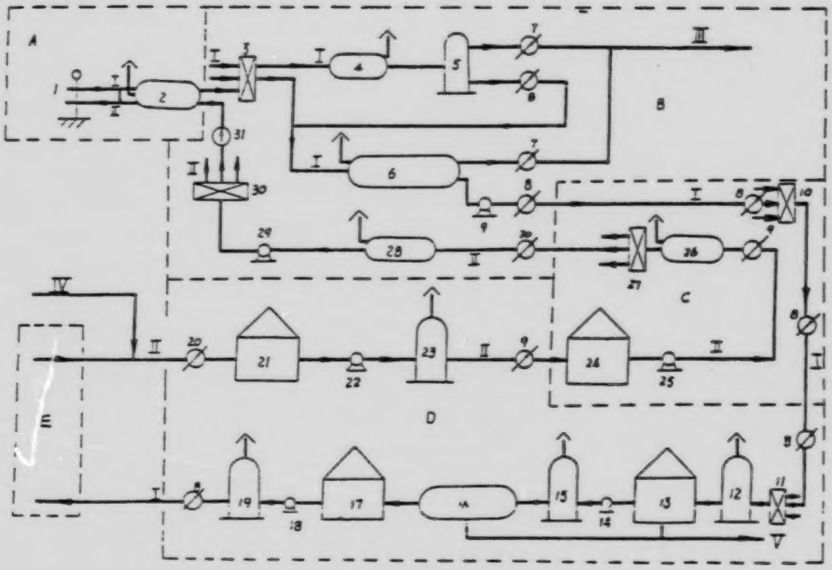
Period	Blending Fluid	Monthly Ton	Production Volume	Oil/H20 Ratio	μ (50C) cp	Density 20C	Prod %
May/82	H20	1317	2370.6	1.8	2593 (HO)	.9581	
June/82	H20	1323	2381.4	1.8			100.0
Aug/82	Oil	1580	1224.6	.77	81 (MO)	.9037 Sep/82	119.0 Oil
1983	1266.3	.63			149.9		
Oct/82	Oil	2500	1330.3	.53	115 (MO)	.9142	189.0

Note: H.O--Heavy Oil
M.O--Blended Oil
Production from 8 Wells

Table 4
Production Data from the Two Blending Process in 1982

Well	2-5-7	2-5-07	2-5-8	2-5-08	3-6-3
(By Water Blending)					
Date	6	6	6	6	6
Water Blending Ratio	1.8	1.8	1.8	1.8	1.8
Daily Production, ton	12.7	5.3	8.1	3.7	5.5
Wellhead Pressure, kg/cm^2 g	2.0	2.5	2.0	2.0	1.8
(By Oil Blending)					
Date	1018 -1103	0801 -0815	1018 -1103	1023 -1103	1024 -1103
Oil Blending Ratio	.35	.85	.47	.70	.66
Daily Production, ton	26.7	8.4	12.9	4.27	5.97
Wellhead Pressure, kg/cm^2 g	1.32	1.45	1.10	1.13	1.26
Heavy Oil Viscosity(50°C), cp	938	1938		3900	2881
Mixed Oil Viscosity(50°C), cp	51.0	52.3	189	125	80.4

Figure 1
Gaosheng Oil and Gas Treatment Facilities



Gaosheng Oil and Gas Treatment Facilities

A: Wellhead installation; B: Metering/boosting station
C: Block station; D: Central Processing Plant; E: Refinery
1: Wellhead; 2: heat exchanger; 3: Manifold; 4: Heater; 5: Test separator
6: Heater/separator; 7: Gas meter; 8: Oil meter; 9: Pump; 10: Manifold
11: Manifold; 12: Heater; 13: Settling tank; 14: Pump; 15: Heater;
16: Electrical Precipitator; 17: Storage tank; 18: Pump; 19: Heater
20: Oil Meter; 21: Storage tank; 22: Pump; 23: Heater; 24: Storage tank
25: Pump; 26: Heater; 27: Manifold; 28: Heater/storage tank
29: Pump; 30: Distribution manifold; 31: Flow control valve
I: Production pipeline; II: Light oil pipeline; III: Gas pipeline
IV: Light crude pipeline; V: Waste water pipeline

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STEAM DISTRIBUTION, CONTROL AND METERING SYSTEMS

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1.0 INTRODUCTION

High pressure steam injection into a reservoir is the principal method used for the recovery of heavy oil. This paper will discuss some design considerations for high pressure steam injection as it relates to heavy oil facilities operating in Alberta, Canada, namely:

- *Central steam generation facilities for distribution of high pressure steam to the injection wells.*
- *Above ground versus underground steam line installation.*
- *Insulation type and heat loss considerations.*
- *Control and metering techniques and choice of intruments for steam injection.*

2. LOCATION OF HIGH PRESSURE STEAM GENERATION FACILITIES

The trend for commercial heavy oil facilities in Alberta, Canada has been that of locating high pressure steam generators in a central facility along with oil and water treating equipment and subsequently distributing the high pressure steam from the central facility to the injection wells. In California, on the other hand, the trend has been to locate oil and water treating equipment in one common facility and then locate steam generators in clusters around the field. In the later case the boiler feedwater is pumped from the central oil and water treating facility to each of the steam generator clusters. The advantages and disadvantages of locating the steam generators in a central location versus locating them in clusters is as follows:

2.1 Advantages of Steam Generators in a Central Location

- *This configuration is better for operations and maintenance since all equipment is situated in one location. This is especially advantageous in cold climates where freeze protection and housing is required.*
- *More opportunity for heat recovery. Since the production generally comes to the plant hot, the heat from the production can be more easily recovered under this configuration to preheat combustion air for steam generators. This will improve the overall thermal efficiency of the project.*
- *Better flexibility. All of the high-pressure steam generators installed will be capable of supplying steam to all of the injection wells. Over the lifetime of a project, this will provide for a higher average oil production rate for the same number of steam generators installed.*
- *Less equipment requirements. The number of spare boiler feedwater pumps, as well as the requirements for additional ancillary equipment (instrument air, fuel and blowdown systems) is less. This reduces the overall cost of the project.*
- *Land requirements are reduced. Since all of the equipment is situated in one location, the amount of land required is less. This is an important consideration if the heavy oil facility is located in an agricultural area, or in other areas where land use is critical.*

2.2 Disadvantages of a Central Location

- *Larger diameter and longer high pressure steam distribution lines are required.*
- *Potential for heat loss is greater due to transporting a higher temperature fluid over a greater distance. However, with proper insulation the heat loss should not be a significant factor.*

Although larger diameter and larger steam distribution lines are required, it is still advantageous to locate the steam generators in a central location.

Factors such as better operations and maintenance, better flexibility, less equipment requirements, and less land requirements outweigh the disadvantages. However, there may be some cases where it is justified to locate the steam generators remotely in clusters. For example, if the use of land is not important, or if the climatic conditions are favourable (i.e. non-freezing climate), then it may be justified. In any case, the requirements for each project need to be evaluated before selecting the final location for the steam generators.

3. ABOVE GROUND VS UNDERGROUND INSTALLATION FOR HIGH PRESSURE STEAM DISTRIBUTION LINES

Most of the heavy oil pilot plants and all of the large commercial scale heavy oil projects in Alberta utilize above ground installation for the distribution of high pressure steam to the injection wells. Only a few pilot plants or small commercial scale projects utilize an underground steam distribution system. Following are the relative merits of each system.

3.1 Above Ground Installation

☐ *Advantages*

a) Installation and insulation of distribution lines is simpler.

b) Design for thermal expansion is easily accommodated.

c) Installation costs are less expensive than underground systems. It has been estimated that underground piping systems cost 25-30% more than above ground systems.$^{(1)}$

☐ *- Disadvantages*

a) Uses more space or land than underground systems.

b) May limit mobility around site, particularly if wells are vertically drilled.

In recent years, the heavy oil industry has been utilizing the concept of directional drilling multi-wells from a central pad. This development minimizes the amount of high pressure steam lines that have to be run. Consequently, the amount of land required under this arrangement is greatly reduced. Mobility around a plant site can be designed for and therefore is not a negative factor. The use of this concept also minimizes the disadvantages for above ground piping.

3.2 Underground Installation

☐ *Advantages*

a) Uses less land, allowing greater mobility around the plant site.

☐ *Disadvantages*

a) Insulation used for high pressure steam lines is generally not compatible with underground installation and requires special design considerations to ensure that there is no moisture leakage into the insulation.

b) Thermal expansion for these high temperature lines also pose a problem and require special design considerations.

c) Installation costs are higher.

To accommodate both the insulation and thermal expansion problems of an underground line, a system that provides a "jacket" for the high pressure steam line has been employed $^{(1)}$ (see Figure 1). In this example, a 3" line with two inches of insulation is used to transport the steam to the well. An 8" diameter pipe encloses and waterproofs the insulated 3" line. The 3" line, with 8" jacket is installed in such a manner that it is brought to the surface in a gentle curvature. Thermal expansion is then taken up with a swivel joint installed at the wellhead. The installation of this system, however, is limited to:

- *small diameter pipe since the flexibility of 3" or 4" pipe is good and,*
- *short distances since there is limited ability for the swivel joint located at the wellhead to take up thermal expansion.*

For larger diameter pipe or longer distances, the pipes could be installed in a "box arrangement" (see Figure 2). This system would then be similar to that of an above ground installation and the thermal expansion of the steam line could be easily controlled. The box arrangement would have to be constructed in such a manner that it would not collapse.

The design for installation of the insulation would have to ensure that there was no moisture leakage; drainage would also have to be provided to ensure no flooding occurs. The installed costs for this system would be even greater than that of the jacketed system.

4. INSULATION AND HEAT LOSS CONSIDERATIONS

The rising cost of energy has resulted in more attention being paid to heat loss. However, thermal efficiency and the economic thickness of the various materials are not the only considerations when designing an insulation system. Other factors which must be considered are chemical attack from both spillage and fumes, the possibilities of physical abuse, fire safety, personnel protection, cleaning difficulties, installation procedures and future requirements of gaining access to insulated pipe and equipment. In the selection of insulation for high pressure steam distribution lines, the insulation should meet the following criteria:

- ☐ *The material's properties, particularly thermal-transport properties, should be consistent so that they do not vary significantly from batch to batch.*
- ☐ *The insulation must retain its mechanical strength when subjected to high operating temperatures over long periods of time.*
- ☐ *Both the insulation and its barrier system should resist mechanical abuse over the life of the project since the piping is generally accessible to workers, is walked on, has ladders leaned against it and tools dropped on the insulation.*
- ☐ *The insulation barrier system has to be effective, allowing little or no water leakage. Penetration of the insulation by water can seriously diminish its insulating properties until it dries out, or can result in permanent mechanical damage of the insulation.*

Calcium silicate is used almost exclusively for insulation of high pressure steam distribution lines in Alberta. Calcium silicate, which is a mixture of lime and silica, reinforced with organic and inorganic fibers, is ideal for this application since it exhibits the following properties:

- *temperature range covered is 38° C to 800° C.*
- *flexural strength is very good.*
- *compressive strength is high.*
- *has good fire resistant properties.*
- *meets specifications for prevention of stress-corrosion cracking of austenitic stainless steel.*
- *recovers thermal properties after being wetted (however, it does loose its thermal properties when wet).*
- *retains thermal and mechanical properties over a period of time, showing very little degradation of these properties.*

The heat loss from a high pressure steam distribution system when using calcium silicate insulation is not a significant portion of the total heat carried in the line. Consider the following example:

Steam flow:	22,675 Kg/hr, 80% quality
Operating conditions:	150 atm at 343°C.
Pipe size:	3" diameter
Insulation:	3" of calcium silicate

The total heat loss for this system is only 0.1% over a length of 100 meters!

Mineral fibre, which is composed of rock and slag fibers bonded together with an organic binder, can also be used. The thermal properties are generally better than calcium silicate. However, since the organic binders used for bonding tend to break down over a period of time, the insulation collapses which causes the mineral fibre to significantly loose its thermal insulating properties. In addition, it is also susceptible to mechanical damage. For these reasons, mineral fibre insulation is generally not used.

In order for the insulation to function properly, strict attention must be paid to its installation. The insulation used generally comes in preformed sections. It is particularly important that these sections be butted-up tight and that both the longitudinal and circumferential joints are staggered when installed. Generally, single layer applications have been found to be adequate. However, if heat loss is a real concern the insulation can be installed in double layers, with the inner joints staggered from the outer joints. The whole insulation should then be covered with an aluminum jacketing to provide protection against weather and mechanical damage. The longitudinal laps of the jacket should be sealed with a flexible adhesive and positioned to shed water. Adjacent sections of the jeacketing should also be provided with a generous overlap.

5 STEAM MEASUREMENT AND CONTROL

5.1 Steam Measurement

Flow nozzles for measuring the flow of high pressure steam to injection wells have generally been the standard in the heavy oil industry in Alberta. A schematic of a flow nozzle is shown in Figure 3. The flow nozzle can operate over a turndown ratio of 3:1 with an accuracy of 2%.

Orifice plates have not gained wide acceptance for the flow measurement of the high pressure steam for injection, since the steam quality is 80% and the flow is two-phase. Advantages of flow nozzles over orifice plates for the measurement of high pressure steam are as follows:

- ☐ *Flow capacity is approximately 60% greater with the same beta ratios.*
- ☐ *Flow nozzles sustain accuracy over a longer period of time.*
- ☐ *They provide more accuracy at higher velocity flows.*
- ☐ *Less subject to damming affect of solids or foreign matter in the flow path.*
- ☐ *Better wear qualities.*
- ☐ *Can be used in piping systems where flange connections are not desired or are not acceptable.*

It is recommended that flow nozzles for use in high pressure steam applications be installed by welding them directly into the piping system. This avoids possible steam leaks that might occur if the flow nozzles were installed by using flange connections. Service life and measurement accuracy has been found to be acceptable for flow nozzles welded in place.

5.2 Steam Control

Control of the high pressure steam flow to the injection wells can be either manual or automatic. For instance, at the Shell Peace River commercial heavy oil project (steam drive process) only the dedicated injectors are controlled automatically, the other wells which receive steam during the initial start-up period are controlled manually. At the Esso Cold Lake commercial heavy oil projects (huff and puff process) all of the wells are on manual control.

Extreme accuracy or control of the steam to injection wells is usually not necessary. A steam flow of 10% of the desired flow is considered to be adequate for the purposes of steam injection to the various wells. The real need for automatic control comes from a requirement to balance flows to individual wells in a multi-well injection system. This requirement would only be necessary if the steam flow to the individual wells is changed frequently. The design characteristics of the control valve must be capable of handling the requirements for large pressure drops, critical flow regimes and sonic velocities, normally associated with high pressure steam services. Construction features of the valve include 316 SS construction (trim only) with stellite hard surfacing, if chlorides are not a problem; if chlorides are present special metallurgy will be required.

6. SUMMARY

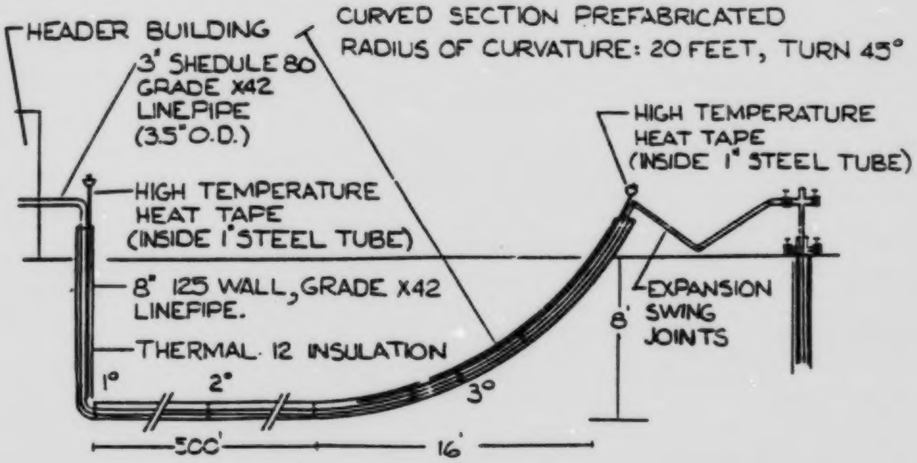
The experience of steam injection for the recovery of heavy oil on a commercial basis in Alberta, Canada has been based upon design considerations that take into account Alberta's climatic and environmental conditions. Some of the design considerations predominately used are:

- ☐ *use of central steam generation facilities for the distribution of high pressure steam to injection wells. Central steam generating facilities are located at the same site with the oil and water treating facilities.*
- ☐ *use of above ground lines for the distribution of high pressure steam. The use of multi-wells directionally drilled from a central pad which has minimized the amount of high pressure steam lines that have to be run and the land use requirements. Lack of mobility around the plant site is therefore not a problem.*
- ☐ *use of calcium silicate insulation since it has good thermal insulating properties and resists mechanical damage.*
- ☐ *use of flow nozzles for measurement of high pressure steam to injection wells.*
- ☐ *use of either manual or automatic control for distribution of high pressure steam to injection wells.*

REFERENCES

- (1)Bland, Linden H.R., "A Combination Steam and Production Flowline Insulated and Buried", Oilsands, 1977.

Figure 1
Steam Injection Flowline, Insulated and Buried (1)


HEADER BUILDING
CURVED SECTION PREFABRICATED
RADIUS OF CURVATURE: 20 FEET, TURN 45°
3" SHEDULE 80
GRADE X42
LINEPIPE
(3.5" O.D.)
HIGH TEMPERATURE
HEAT TAPE
(INSIDE 1" STEEL TUBE)
HIGH TEMPERATURE
HEAT TAPE
(INSIDE 1" STEEL TUBE)
8" .125 WALL, GRADE X42
LINEPIPE.
THERMAL 12 INSULATION
EXPANSION
SWING
JOINTS
8'
1°
2°
3°
500'
16'

1° CENTRALIZER WELDED 3" & 8"
2° CENTRALIZER EVERY 10' WELDED TO 3" ONLY.
3° CENTRALIZER EVERY 3' WELDED TO 3" ONLY.

Figure 2
Box Arrangement for Installation of Underground Lines

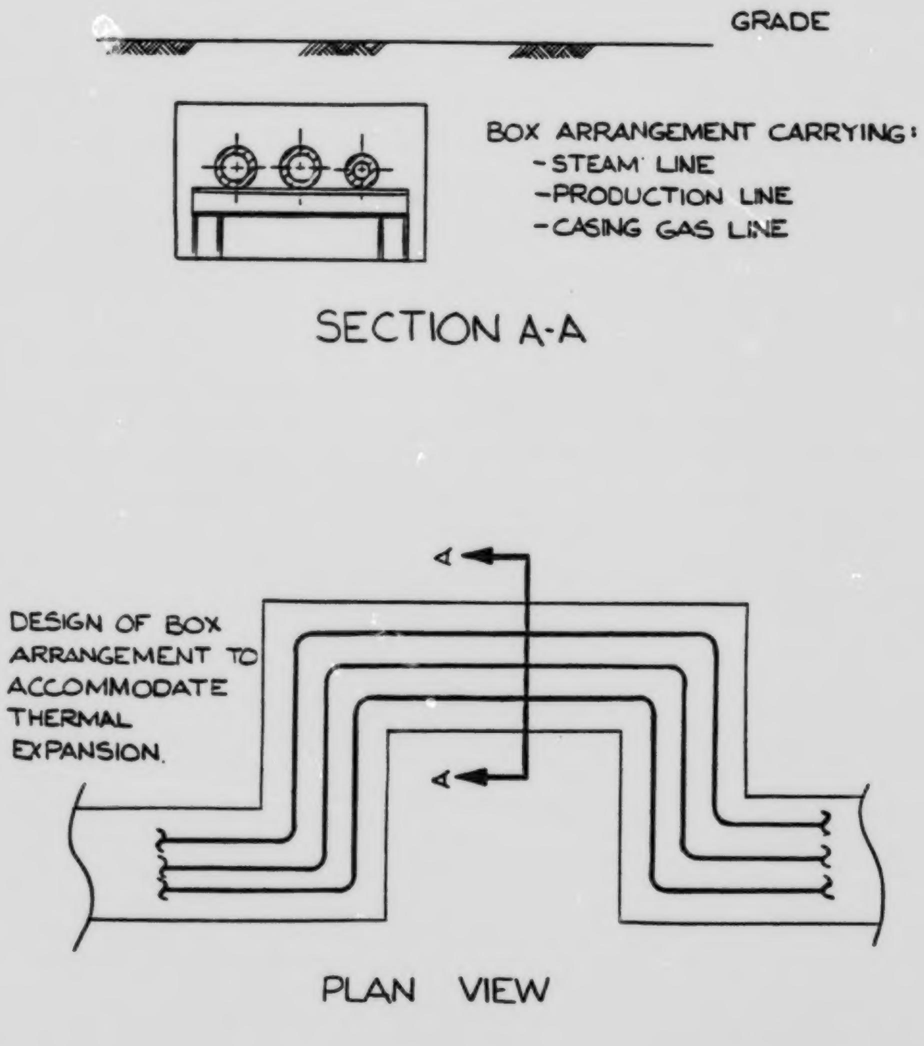
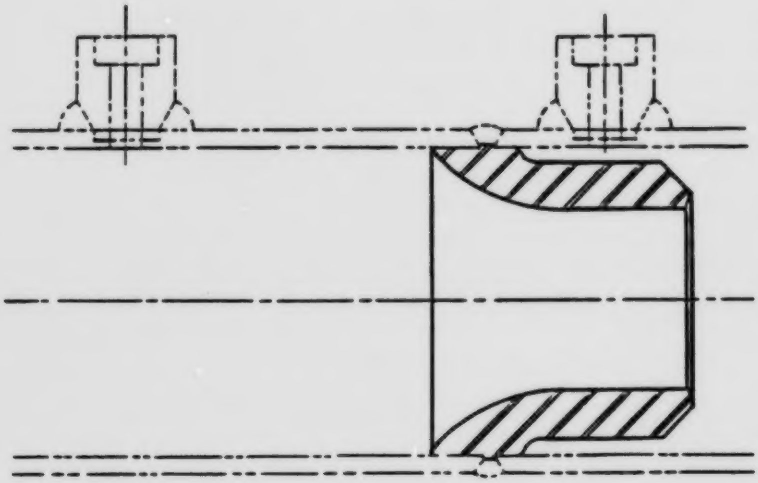

GRADE
BOX ARRANGEMENT CARRYING:
-STEAM LINE
-PRODUCTION LINE
-CASING GAS LINE
SECTION A-A
A
A
DESIGN OF BOX ARRANGEMENT TO ACCOMMODATE THERMAL EXPANSION.
PLAN VIEW

Figure 3
Flow Nozzle (Weld-in Type) for Measurement of High Pressure Steam



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HEAVY OIL GATHERING AND PIPELINING TECHNOLOGY

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China Petroleum Planning and Engineering Institute

ABSTRACT

Since early 1970's when China began to produce from her abundant heavy oil reserve, four different methods for gathering heavy oil from wellheads to batteries have been implemented at various production sites. These four methods involve lowering oil viscosity either by blending with water, light oil, condensate, or by heating. It is fairly obvious that selection of these methods should be based on oil properties, recovery and treatment processes and field conditions. Economic consideration of an overall production system from gathering, pipelining to oil refining are important factors for determining which methods to use. To select a gathering system based on heating effect, best utilization of heat energy in produced fluids must be carefully examined.

OIL BLENDED WITH WATER

This gathering method involves oil blended with water containg surfactants. It had been used in the Gudao oil field where gravity of oil from the south area was 0.957 at 30°C (15.9 API) and viscosity of the degassed crude was 400-2000 cp at 50°C. Viscosity of the crude from the west area was 500-3500 cp. In this method, water was heated to 65 to 75°C at the blending station and subsequently metered prior to injection into casing or production tubing at wellheads. The injected water mixed with produced fluids in wellbores and eventually flowed to batteries where water was separated from oil with a separator for reuse. With water injected at a water to ratio from 1 to 1.4 and surfactant dose rate at 50 ppm, the apparent viscosity of the blend dropped 50 times allowing uninterupted production from the field for many years. As more water flood technology is being used recently to produce oil from the field, both the temperature and water content of the produced fluids gradually increase. When water content in produced fluids reached 65-70%, water injection for heavy oil pipelinign was discontinued without affecting production.

It is obvious from field experience that the process has its limitation and is not suitable for highly viscous crude oil. For example, the process was tried without much success at Gaosheng field in Liaohe where crude oil viscoisty lies between 2000-4000 cp at 50°C, and specific gravity between .94 and .95 (API 19 to 17.5) at 20° C. The Gaosheng crude is apparently more viscous than the Gudao crude oil. For some reasons, the process did not produce stable oil-in-water emulsion in the flowline. Friction loss in the flowline and wellhead pressure were very high, thus severely affecting oil production. Another undesirable problem associated with this process is, according to production experts, contamination of the pay zone by the surface active water which may affect oil recovery efficiency.

Selection of the process can only be rational when condensate is not economically available or heavy oil upgrader cannot be economically built at or near the field. However, one has to keep in mind that there are shortcomings in the process such as corrosion and emulsion treatment problems which need to be resolved.

LIGHT OIL BLENDING PROCESS

Because of the above problems associated with the water blending process, light oil blending process was tested at the Gaosheng field in Liaohe since 1981. Since the test was very successful, the process was implemented and had completely replaced the water blending process by the end of 1983.

To apply the process at the field, light oil of 18.16 cp viscosity at 50°C and 0.888 specific gravity at 20° C (28 API) was heated at heavy oil batteries and again at blending station before it was metered and distributed to various wellhead casings or production tubings. Temperature of the light oil was normally maintained higher than 60° C. With the blending ratio of light oil to produced liquids kept at 1:0.45 and 1:1, it was possible to reduce viscosity of the mixture to 325.55 and 85.6 cp (50° C) respectively. The process was able to reduce static head pressure of liquid column in tubing as well as friction loss in the flowline. It is quite remarkable that some wells are revived by the new blending process. Average daily production experienced an increase of 19% to 89%. Meanwhile, oil water separation efficiency was greatly improved, lowering water content in the treated oil from the 1-3% down to below 0.5 %; and at the same time reducing the oil content in produced water from 1000 mg/L to about 10 mg/L.

Obviously the light oil blending is effective in viscosity reduction and can be a feasible process if sufficient supply of light oil is available. One negative impact of the process is that it raises the paraffin content of heavy oil, which itself is an excellent raw material for high quality road asphalt, and lower the quality of light oil products because of refining difficulties associated with the blend. Consequently, best utilization of both the heavy oil and light oil resources is more difficult to achieve. On the other hand, it is more beneficial economically to upgrade heavy oil based on the following preliminary estimation: one million tons of heavy oil blended with light oil is worth only 120 million yuan in today's market but the equivalent upgraded product is valued at 420 million yuan, a net increase of 300 million yuan.

It is obvious from the above discussion that when selecting a gathering system for heavy oil production, one must decide which final products are most desirable and what economical benefit the overall operation will bring.

OIL BLENDED WITH CONDENSATE

In an experiment carried out at Liaohe Gaosheng field in 1985, No 35 diesel with 1.26 cp viscosity was blended with heavy oil at a blending volume from 23% to 26%. The blend viscosity was effectively reduced to 140 cp from the blending test. However, recovery of condensate was not possible at the time due to lack of facilities. Also, the economics of the process was considered to be poor as the added value of condensate was not sufficiently recovered by the market value of the blended product. The experiment was consequently discontinued.

The process is only economically feasible when condensate recovery and transportation facilities are available or when there is sufficient supply of condensate. This is not the case at the Liaohe Gaosheng field at the present time. Should, however, its refinery be modified to produce mainly high quality asphalt and at the same time, process the below 420°C fractions into light products with a medium pressure hydrocracker, the condensate gathering process could become very attractive since there would be plenty of 170-280° C diesel oil fractions available for reducing the viscosity of the blend to 100 cp and that the diesel oil fraction is recyclable in such an operation.

In order to make a sound and rational selection of a gathering system for heavy oil production, one must conduct a fairly comprehensive investigation ranging from the transportation and upgrading of the heavy oil product, the location and capabilities of an upgrader and refinery, product desirability and market needs.

VISCOSITY REDUCTION BY HEATING

The No. 9 area of Karamay is a shallow reservoir with depth ranging from 160 to 240 meters. At the reservoir temperatures from 15 to 18° C, the oil is immobile and viscous as the viscosity of the degassed crude can be as high as 2000 to 3000 cp. Oil can readily be recovered using thermal process through steam injection. As shown in Table 1, viscosity of heavy oil is sensitive to temperature; when temperature is increased from 50°C to 80°C, viscosity of the heavy oil drops from 316 to 25.15 cp. Heating is an effective mean for reducing viscosity of heavy oil.

A single pipeline is being used in this area for steam injection as well as for production. During the stage when cyclic steam stimulation process was applied, the line was used alternatively for steam injection and production. During the steam drive stage, some wells were injected with steam while others were producing. The service ratio of the pipeline was high and little pipeline modification was required when recovery process was shifted from cyclic steam stimulation to steam drive operations. The single pipeline was easy to manage and its capital cost was only half of that of a double or triple line. The selection of a gathering system for light oil is relatively simpler than for the heavy oil due to the fact that for the light oil, production, gathering, transportation and refining operations are less interdependent. For the heavy oil, selection of a gathering system, which could affect oil properties and therefore the refining operations and the final products, is sound only if it is based on an overall consideration of the integrated system from production, transportation to refining. Generally speaking, gathering system is largely determined by the recovery process. For the heavy oil operations, sometime it is necessary to make adjustments on the recovery process or the refining operations in order to accommodate a heavy oil gathering system chosen based on an economic study.

SELECTION OF THE HEATING METHOD FOR HEAVY OIL GATHERING

Temperature is one of the important parameters for a heavy oil gathering process, especially the heating method. The heating method can be feasible if existing facilities for steam injection and thermal recovery are utilized to heat produced fluids at wellheads to an appropriate temperature according to the properties of the oil produced. The following can be important factors for rationalizing the selection of the heating method:

i) Increase Production during Early CSS Cycle

Take Liaohe Gaosheng field as an example. The reservoir at Gaosheng is between 1510 and 1700 meters deep. Viscosity of the oil in the formation under reservoir conditions is between 74 and 805 cp. Under the same conditions, the degassed crude exhibits viscosity as high as 1000 to 4000 cp. The reservoir was thought to be able to provide a sustained liquid yield. However, due to contamination during drilling and workover, the production was low. Production increase was achieved by steam stimulation through a thermal unblocking mechanism. The mechanism exhibited low production at the early cycle followed by a sustained and relatively stable production period. One of the reasons for the low production at early cycle is due to temperature limitation of the gathering facilities below 100° C. Because of this limitation, wells are usually shut in for over a week or two at the end of the steam injection. During this period, the rapid drop of temperature due to heat loss and poor bottomhole steam quality usually results in the disappearance of production peak. If oil temperature at the wellheads could be raised to 120°C, it is possible to shorten the shut-in period and thereby increase production during early cycles.

ii) Best Utilization of Heat During Early Cycles of the CSS Process.

At the early production cycles of the cyclic steam stimulation process, temperatures of the produced fluids can reach as high as 150° C. Because of the temperature limitation of the fluids gathering system, pipeline and instruments, the hot fluids from the wellheads are cooled in a cooling vessel by natural convection. Sometimes, a cement truck was used to circulate water from a water truck to a heat exchanger at a wellhead to cool fluids to 80-90° resulting in a loss of energy.

The loss of energy was quite substantial as in the case of Shanjiasi 2-3 well in Shengli oil field. After two months of production during the first cycle, the well produced 105 tons per day of fluids with temperature higher than 100°C. Total cumulative production up to this time was 8,000 tons all of which were cooled in a cooling vessel and trucked out. Energy loss was estimated to be 580 million Kj when produced fluids were cooled from 125°C to 90° C. If produced fluids were allowed to cool to 110° C, the amount of energy loss can be reduced to 243 million Kj. The difference in the energy loss between the two cases, estimated to be 337 million Kj , could be utilized to lower oil viscosity and reduce pressure loss in the gathering system, with the remaining energy recoverable in the central treating plant through heat exchangers to raise boiler heat water by as much as 20° C and save 7.5 tons of fuel. Substantial boiler fuel saving of 585 tons per production cycle can be realized from recovering some of the energy from all the 78 wells in the field.

iii) Heating process is simple

The heating process, which requires no pump, heater and less instrument and piping, is a lot simpler than the diluent or water blending process in terms of operation and equipment maintenance. Take Liaohe 1-7-5 fault block as an example. Currently, the field is producing from 15 wells over the one square kilometer of the pay zone using the cyclic steam stimulation process. If heating were to replace the current light oil blending process for the produced fluids gathering system, it would save capital cost, electricity, and fuel consumption by as much as 10.9, 5.9, and 2.4 % respectively.

iv) Steaming Schedule

Field experience from the cyclic steam stimulation process shows that daily production from a well decreases with production period as the formation temperature drops. The trend could be reversed by shortening production cycle and by steaming for the next cycle before the formation drops below a certain temperature or before produced oil viscosity at wellheads rises beyond 1000 cp. Shortening of the production cycle would certainly consume more energy but it is more than outweighed by other benefits such as production increase, ease of fluids gathering and pipelining and reduction in pressure loss. Similar experience has been observed for the steam flood process where fluids temperature at wellheads was around 130°C. Fluids at such a high temperature could easily be gathered and pipelined without requirement of additional heating energy.

It should be emphasized that the fluids gathering process with heating is feasible only when residual energy in produced fluids from steam stimulation can be fully utilized. The process becomes economically unrealistic if produced fluids are to be heated on the surface. Usually, the amount of heating energy required would not be offset by the benefits from the reduction in fluid viscosity and pressure loss. The process also requires better insulation materials such as fiber glass, sillicate foam or heat resistant polyester foam to reduce heat loss from pipelines which must be installed above ground rather than underground

CONCLUSIONS

- ☐ *1) The processes to reduce heavy oil viscosity by blending with surface active water, light oil and condensate, and by temperature effect were successfully applied at various oil fields in China to deliver oil from wellheads to central treatment plants.*
- ☐ *2) For future heavy oil projects, selection of a viscosity reduction process for fluids gathering and pipelining should be based upon overall economics of an integrated operations from production, transportation to refinery.*
- ☐ *3) Heavy oil surface gathering system is closely related to oil recovery process. For a steam stimulation project, heating process for oil gathering is feasible if residual heat in produced fluids can be fully utilized to affect a viscosity reduction, and appropriate fluids temperature at wellheads can be maintained by shortening of production cycles.*

ACKNOWLEGMENT

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Table 1

Viscosity of Heavy Oil from Various Fields

Temp C	Liaohe Field Shu #1 Area	Shengli Field Shanjiasi	Liaohe Field Jin No 89	Karamay Area #9
20	----	----	----	3000
30	----	----	----	1300
50	32000-42000	6980	4500	320
60	----	3570	1800	----
70	2052-3852	1637	760	----
80	----	808	----	----
90	654-1635	452	220	----
120	----	---	174	----
150	55-76	---	21	----

Note: Viscosity in cp.

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RHEOLOGY OF SHANJIASI HEAVY CRUDE/WATER EMULSIONS

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ABSTRACT

The rheological characteristics of Shanjiasi heavy crude/water emulsions at various temperatures and oil concentrations are identified by analyzing the rheological data obtained from the concentric cylinder viscometer. It is shown that (1) the viscosity of heavy crude can be greatly reduced by forming oil-in-water emulsion, (2) the variation of the emulsion viscosity with temperature is much less than that of the heavy crude and (3) the viscosity of emulsions increases sharply with the increase of the oil concentration. A new equation is proposed to correlate the viscosity of the emulsions with oil concentration.

INTRODUCTION

Difficulties in pipeline transportation of heavy crude oils arise from the high viscosities even at high temperatures. Current methods for pipelining heavy crudes include heating and insulating the pipelines, blending the crude oils with hydrocarbon diluents or a combination of both. Although the heating and insulating method has been proven effective, it faces the problems such as considerable fuel consumption, high demand of manpower and equipment, and difficulties in restarting after emergency shotdown. Blending the heavy crude oil with diluents is a simple and reliable method that is often used. However, in some cases, it may affect the quality of the refined products of the crude oil. Also the availability of the diluents may limit the use of this method. As a result, method of transporting the crude oil as an "oil-in-water" emulsion or suspension has been investigated as an alternative [1,2,3,4].

The oil-in-water emulsion method involves mixing oil with an adequate amount of water and appropriate surfactant. At a proper temperature, the water-and-oil emulsion is formed by despersing oil into water under the effect of shear stress. Consequently, the frictions between the crude oil and the inner wall of the pipeline become the fractions between the water and the inner wall. The pipeline pressure drop is therefore reduced.

The oil-in-water emulsion method incurs the costs of surfactant, water separation and treatment. The costs of the blending method include the back tansportation of the light ends of the crude oil to the blending point, repeated refining of the blended oil and loss of light ends during refining. The heating and insulating method aquires the cost to meet the heating requirement. For long distance pipelining, the oil-in-water emulsion method appears to be more economical.

In the thermal recovery process using the steam soaking method, the average water content in the crude is usually up to 30-40%. In this case, low viscosity of oil in-water emulsion may be formed in-situ by injecting surfactant to the wellbore. As a result, the friction resistance in both gathering line and long-distance pipeline can be reduced. There are several cases of sucessful application. Simon et al [3] applied this method to heavy oil production and McClaflin et al (4) replaced the hydrocarbon diluent with aqueous solution of of surfactant in heavy crude production. Similar method was also used in Liaohe oil field, China. Nevertheless, there are many technical problems remain unresolved in applying this method. Recently, there has been active studies in Liaohe oil field and other countries [1,5,6,7]. This work mainly concerned with the laboratory study on the rheological characteristics of Shanjiasi crude/water emulsions.

EXPERIMENTAL

Physical Characteristics and Viscosity-Temperature Relationship ofShanjiasi Crude

Shanjiasi crude may be classified as a naphthene-based crude. It has high specific gravity ($d=978.2 Kg/M^3$), viscosity and resin content, but low wax content and pour point. The viscosities of the crude at various temperatures are shown in Table 1. In a temperature ranging from 20° C to 60° C the crude behaves as a Newtonian fluid.

Table 1 Viscosities of Shanjiasi Crude at Various Temperatures

Temperature °C	20	30	40	50	60
Viscosity mPa.S	$4.97x10^5$	$1.15x10^5$	$3.18x10^4$	$1.06x10^4$	$4.24x10^3$

■ Surfactant and Its Concentration

The first problem encountered in using the oil-in-water emulsion method is to select an effective and low-cost surfactant. In our experiments, a low-cost surfactant-H"Y, recently formulated by the Petrochemical Synthesis Division, East China Petroleum Institute was used. It is an anionic surfactant. After several experiments, it was found using 0.1% surfactant in water would form stable oil-in-water emulsions at temperatures from 10° C to60° C. With shear stress as high as 300 Pa, there was no oil-water separation or reverse emulsion being observed. The separated emulsions caused by static settlement could be despersed easily after slight agitation and subsequently regained its low-viscosity characteristic. In fact, it was recoganized that only 250 PPm of surfactant was required to achieve stable oil-in-water emulsions. However, at 0.1% concentration, the droplets having diameters from several microns to one hundred microns or larger could be obtained.

■ Rheological Measurement of Heavy Crude/Water Emulsions

❑ *(1) Instrument*

A concentric cylinder viscometer RHEOTEST-2 was used. This viscometer was found suitable for rheological measurement of oil- in-water emulsions. It required that the gap between the two cylinders be at least three times greater than the diameter of the largest particles in the sample in order to avoid erroneous readings. In our experiments, the viscometer had a cylinder radius ratio of 0.94 and a cylinder gap of 1.2 mm.

❑ *(2) Procedure*

In order to make the sample homogeneous, it was first agitated at the highest shear rate in the viscometer for 20 minutes. The rheological measurements were subsequently carried out starting from low shear rate to higher ones. For rheologically complex materials, shear stress often varies with time at constant shear rate. The data at the quasi-equilibrium state is generally used to identify the rheological characteristic of the material studied. A quasi-equilibrium state means that the state at which the shear stress remains constant for a period of time at a constant shear rate. There is no standard to determine the quasi-equilibrium state. Each investigator may have his own standard for specific materials. In this study, the quasi-equilibrium state was considered achieved when the shear stress had remained constant for 10 minutes at a constant shear rate. Experiments showed that beyond the quasi-equilibrium state, additional shearing caused no greater than 5% deviation from the shear stress at the quasi-equilibrium state.

RESULTS AND DISCUSSION

■ 1. Data Treatment

During the course of the experiments, it was observed:

(1) For the same sample and a given shear rate, the measured shear stresses and the corresponding viscosities increased with the increase of the gap between the two cylinder wallsof the instrument.

(2) The variations could be reduced by decreasing the emulsionparticle sizes with the increase of the surfactant concentration. Following this, the rheological data measured at different gaps from 0.4 mm to 3.8 mm became identical when the emulsion particle sizes remained at several microns.

(3) If the fluid slip effects were ignored, the deviationsin the calculated viscosities might be up to -70%. Thedeviations generally depend on the oil concentration and the temperature.The mechanism of the wall slippage, its influencing factors,and the corrections required for the measurements will bediscussed in another paper. All the rheological data obtainedin this study was corrected for the slippage effect.

■ 2. Rheology of the Heavy Crude/Water Emulsion

Presented in Fig. 1 is the rheogram of Shanjiasi crude/0.1% H"Y emulsions with various oil concentration at 30° C. As can be seen, the rheological characteristics of the emulsions can be described with the power-law model:

$$\tau = \kappa . \gamma^{\eta}$$

(1) The flow behaviour index, η, is basically unity for emulsions with oil concentration $\phi \leq 0.7$. When $\phi \geq 0.75$,

the pseudoplastic behaviour becomes more obvious as the oil concentration increases.

3. Viscosity-Reducing Effect of the Heavy Oil/Water Emulsions

The viscosities of the emulsions at different oil concentrations and temperatures are shown in Table 2. Note that the measurements were carried out at a shear rate of $\gamma = 100$ 1/s. The quantities, η, and η_c are the viscosities in mPa.s of the emulsions and the crude respectively. (see Table 2)

The results indicate that:

(1) The viscosity of the pipeline fluid can be reduced significantly due to oil/water emulsions. For example, at 30° C, the viscosity of the emulsions with oil concentration of 70% is lower than that of the crude by three orders of magnitude.

(2) The lower the temperature is, the stronger the viscosity reducing effect of the emulsions is.Further study on O/W emulsions of different crudes showed that the effect of the oil viscosity on the emulsion viscosity was not evident for $\phi \leq 0.7$ This implies that the oil-in-water emulsion tech nology would be more beneficial for more viscous crude transportation.

4. Viscosity-Temperature Relationship of the Heavy Crude/Water Emulsions

Shown in Figure 2 are the relationships between the relative viscosities η_r and temperature, t, of Shanjiasi crude/0.1% H"Y emulsions. The relative viscosity, ηr , is defined as the ratio of the emulsion viscosity, η_r, to that of the continuous phase, η_r, ie. $\eta o = \eta / \eta_o$

Several observations can be made from Figure 2.:

(1) For oil concentration.$\phi \leq 0.65$ and temperature $t > 20^\circ$ c, does not vary with temperature and η_r increases slightly with the decrease of the temperature when $t > 20^\circ$ c.

(2) For $\phi \geq 0.7$, η_r increases exponentially with the decrease of temperature. The following equation can be used to correlate the relative viscosity with temperature: $\lg(\eta_r) = a + bt$ (2)

where a and b are constants for each emulsion system. The variation

of the emulsion viscosity with temperature can be described using an equation identical to equation (2) in a range of oil concentrations from 0.5 to 0.8 and temperatures from 10° C and 60° C:

$$\lg(\eta) = A + Bt \qquad (3)$$

For Shanjiasi crude/water emulsion with an oil concentration Ø=0.75, $B = -1{,}25 \times 10^{-2}$. Values of]B] would be less for smaller Ø. As for the crude, $B = -5.57 \times 10^{-2}$ at temperatures from 20° C to 50° C. This ilustrates that the viscosity variation of the emulsions with temperature is much less than that of the crude. This characteristic is advantageous for transporting heavy crudes as an oil-in-water emulsion over a long distance at low temperatures.

5. Viscosity Versus Oil Concentration

Figure 3 shows the viscosity, η, vs. oil concentration, Ø, of Shanjiasi crude/0.1 H"Y emulsions. As can be seen, the emulsion viscosity increases sharply with increasing oil concentration. The following equation can be used to correlation η and Ø:

$$\lg\lg(\eta) = c + d\varnothing \qquad (4)$$

In fitting the data, the correlative coefficients are all greater than 0.99 and the average relative errors do not exceed 20%.

It was observed from Figure 3 that and Ø could also be correlated sectionally as straight lines. The experiments on waxy crude and heavy crude emulsions by Marsden et al (3,8,9,10) showed that on a semi-log plot the relationship between η and Ø was linear or sectionally-linear. The Richardson equation was used to correlate η with Ø:

$$\eta = \eta_o e^{K\phi} \qquad (5)$$

$$\eta_r = e^{K\phi} \qquad (6)$$

where k is the parameter related to the emulsion property. It is often found that η_o in Equation (5) regressed from the data can be of great difference from the viscosity of the continuous phase. Moreover, Equation (6) usually failed to fit the data satisfactorily. We suggest that if equation (5) is used, n o be treated only as a correlative coefficient without considering its physical significance. Otherwise, equation (6) should be modified as following:

$$\eta_r = C e^{K\phi} \qquad (7)$$

where C is a parameter related to the emulsion property. Both methods are the same in substance.

CONCLUSIONS

- *(1) The power-law model can be used to describe the rheological characteristic of Shanjiasi crude/water emulsions. The emulsions behave as Newtonian fluid for Ø≤0.7. For Ø≥0.75, the emulsions exhibit pseudoplastic behaviour.*
- *(2) Significant viscosity reduction is observed in Shanjiasi oil/water emulsions. The viscosity of the emulsions at Ø=0.7 is lower than that of the crude by three orders of magnitude at 30°C. The lower the temperature is, the stronger the viscosity reducing effect is.(3). For Shanjiasi oil/water emulsions, the variation of the viscosity with temperature is much less than that for the curde. Equation (3) can be used to correlate η and t.*
- *(4) The viscosity of Shanjiasi crude/water emulsions increases sharply with increasing oil concentration. The relationship between h and Ø can be described with equation (4).*

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Table 2

Viscosity of Heavy Crude/Water Emulsion

t °c	10		30		50	
Φ	N	N/Nc	N	N/Nc	N	N/Nc
0.6	39.16	1.6 x 10	17.03	1.5 x 10	12.43	1.2 x 10
0.7	163.24	6.5 x 10	131.56	1.1 x 10	54.07	5.1 x 10
0.75	-	-	210.94	1.8 x 10	112.53	1.1 x 10

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Figure 1
Rheogram of Shanjiasi Crude/0.1% H"Y Emulsions t= 30° C

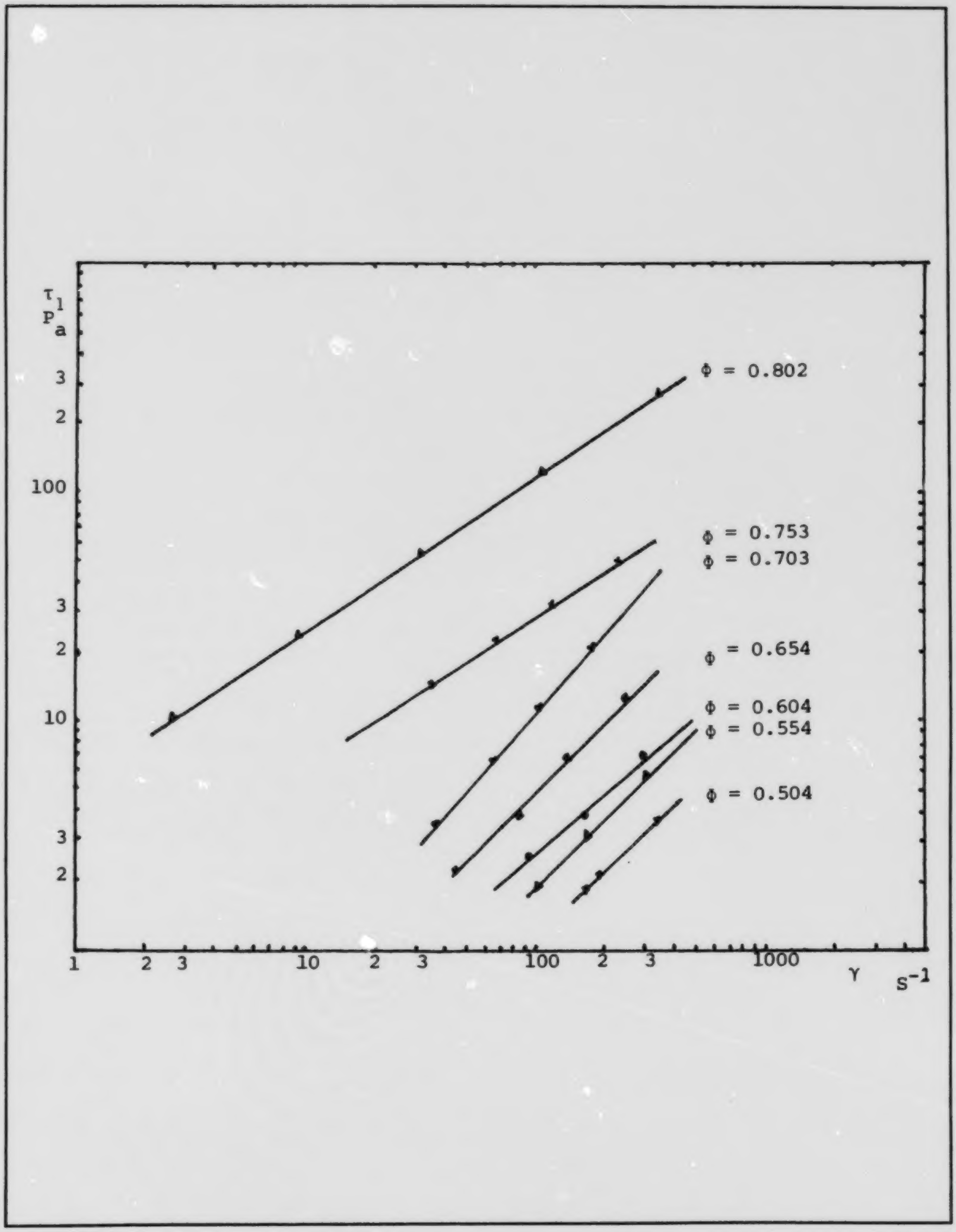


Figure 2

Relative Viscosity vs Temperature Relation of Shanjiasi Crude/0.1% H"Y Emulsions γ=150 s^{-1}

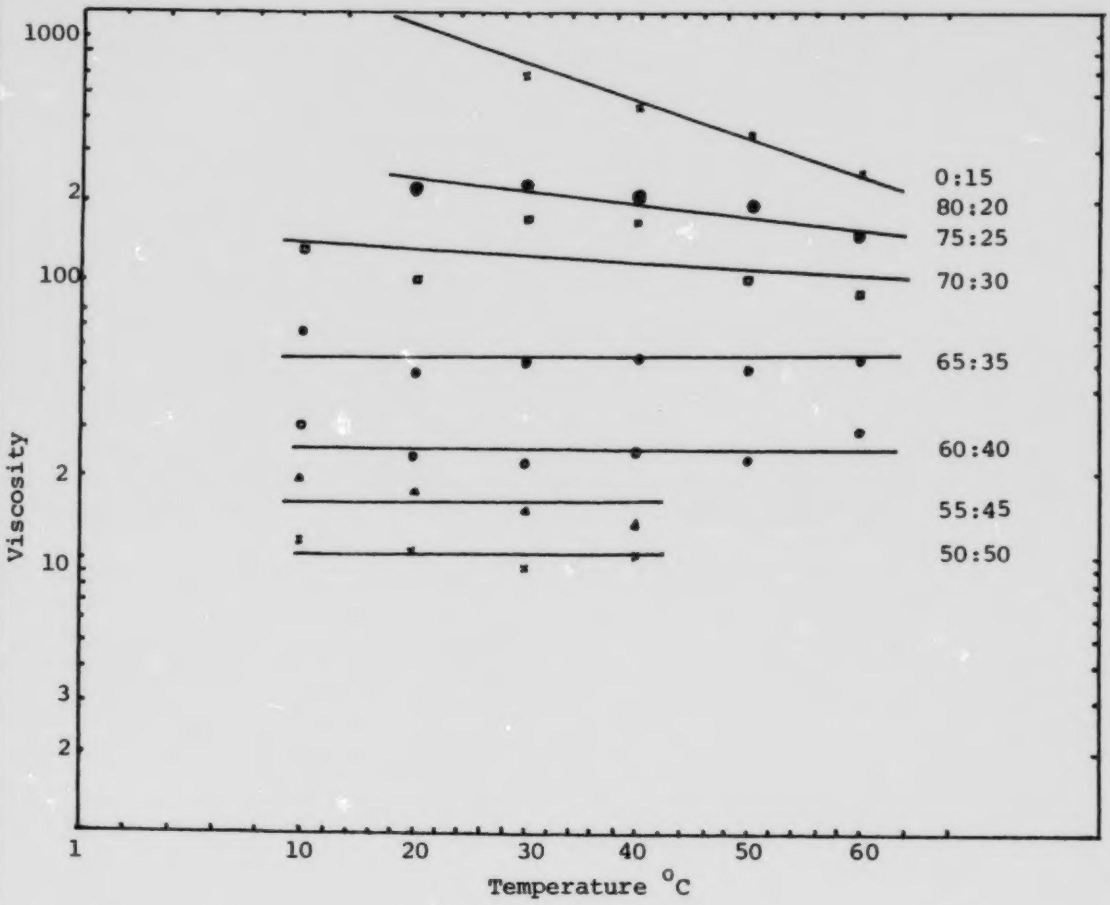
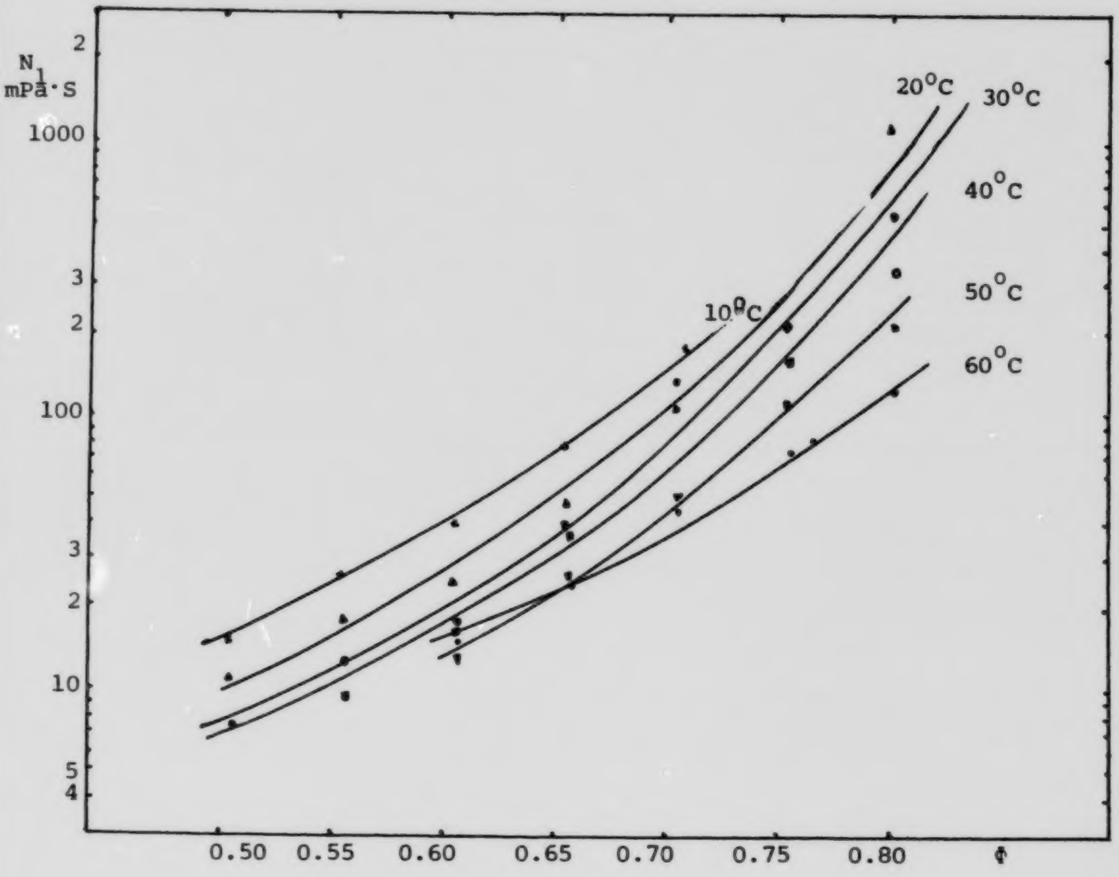


Figure 3
Viscosity vs Oil Concentration Relation of Shanjiasi Crude/0.1% H"Y Emulsions γ=100 s^{-1}



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PRODUCED WATER TREATMENT TECHNOLOGIES FOR RE-USE OR DISPOSAL

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INTRODUCTION

The decrease in reserves of conventional oil in Canada has resulted in the commercial development of surface mineable and in-situ heavy oil deposits. Recovery is currently either by mining for those deposits located near the surface, or by in-situ thermal stimulation techniques for deposits below 200 m depth. Those heavy oil deposits that are buried too deeply to be surface mineable, require some means of mobilizing the viscous oil. This is most frequently achieved by introducing heat in the form of hot water or steam or by in-situ combustion into the reservoir, thereby reducing oil viscosity and making it more amenable to recovery.

In Alberta, Canada, in-situ heavy oil production commonly requires injection of 2 to 3 barrels (320L - 480L) of water in the form of steam for every barrel of oil produced. Along with the bitumen, the in-situ injection facility recovers between 0.5 to 20 barrels (80L - 3200L) of water for every barrel of oil recovered. Generally steam stimulation sites in Canada produce approximately 4 barrels (640L) of water per barrel of oil recovered. After primary treatment, this produced water is usually re-injected in deepwell formations for permanent disposal.

Disposal of produced water by deepwell injection may be economical and environmentally acceptable in an area of abundant water resources and unlimited capacity for deepwell disposal. Unfortunately, in many heavy oil production areas, these conditions do not exist. Regulatory and resource allocation pressures dictate that commercial in-situ operations maximize produced water reuse. In Alberta, concerns about water resources and their conservation have prompted the Province to limit groundwater extraction for oil-field development to 1350 m^3/d. Treatment of the produced water or reuses such as in steam generation is, therefore, becoming a requirement.

Figure 1 shows an overall schematic for the treatment of oil/water mixture collected from a typical insitu operation. The oil/water mixture is routed through a 3-phase separator and a primary separator to remove gases and to separate produced oil from produced water. The oil-rich stream is subjected to emulsion breakup treatments to produce sales oil.

Produced water from the primary separator and from the emulsion treatment process (termed as "primary" produced water) is directed to a skim tank or an induced gas floatation unit (IGF) for oil removal. Depending on the end use of the produced water, it may be either re- injected into the formation or reused as feedwater in an injection boiler. Further treatment is normally necessary if the water is reused either as utility water or in industrial boiler.

This paper reviews the variation in the quality of produced water, the technology for treatment and reuse of produced water, and current practices in the treatment plants built to date in Canada.

COMPOSITION OF PRODUCED WATER

Table 1 gives the range of composition of the primary treated produced water based on the data collected by Environment Canada over the past several years and Monenco's in-house files. The table shows that produced water is basically a dilute sodium and potassium chloride solution contaminated with silica, organic matters and soluble hydrocarbons.

The principal constituents which affect the treatment of produced water for reuse in steam generation are oil, suspended solids, hardness, silica and total dissolved solids (TDS). Hardness concentrations range from 0 to 10,200 mg/L with typical value around 400 mg/L. Esso Resources Ltd. Cold Lake facility has hardness of around 140 mg/L. Oil and grease concentrations range from 0 to 44,000 mg/L. The maximum figure probably represents a malfunction of the primary field separators. A typical value will be in the order of 50-2000 mg/L. The total silica levels range from 0-300 mg/L SiO_2. Shell, Peace River has reported silica of 100 mg/L while Esso, Cold Lake has recorded 250 mg/L.

In Alberta, soluble or reactive silica concentrations in groundwater range up to 30 mg/L SiO_2. Much higher values have been encountered in Indonesia and Mexico possibly due to higher temperatures and pressures associated with seismic activities. The exposure of the underlying strata to high pressure steam may well increase the silica levels in produced water.

Total dissolved solids concentrations range from a low of 2,300 mg/L to a high of 77,000 mg/L with values of 6,000 and 15,000 mg/L recorded at Esso, Cold Lake and Suncor, Fort Kent sites.

In addition to the above constituents, produced water may also contain dissolved oxygen, though the levels are normally low (less than 1 mg/L) due to produced water temperatures (21°C-91°C). The presence of dissolved free hydrogen sulphide and carbon dioxide have also been reported. Their concentrations depended on oil separation, pH and the carbonate, bicarbonate and sulphide concentrations.

In addition to the variation in produced water composition due to location of in-situ facilities, variations with respect to time at a given location have also been observed. Low TDS produced water is frequently produced in the early stages of the production phase, whereas high TDS produced water is observed in the latter part of the cycle.

DISPOSAL OF PRODUCED WATER

Generally, produced water from in-situ recovery pilots in Canada is disposed of through deepwell injection. Discharge of produced water to surface streams is not permitted. As the pilot facilities expand and the quantity of produced water becomes significant, the industry normally recycles as much water as practicable to minimize the volume of freshwater usage. As stated earlier, Alberta has recently developed guidelines which restrict the extraction of freshwater at in-situ operations, thus encouraging the reuse of produced water.

For disposal through deepwell injection, the water is normally treated to remove suspended solids and oil. The treatment is similar to (though not as stringent as) that for reuse for steam generation. Apart from oil and suspended solids removal, it may be necessary to treat produced water to minimize the problems and costs associated with formation plugging. Therefore, it is necessary to evaluate each situation carefully, to ensure compatibility with the formation water to minimize or eliminate precipitation and hence prevent the plugging problems in the formation.

REUSE OF PRODUCED WATER FOR STEAM GENERATION

There are a variety of boiler designs that may be considered for generating steam from produced water. Depending on the boiler used, treatment will vary from virtually zero pretreatment in the case of wet oxidation process to the complete elimination of dissolved solids for high pressure superheater utility type boilers. The wet oxidation boiler is a special case, in that because of the reaction chemistry the steam is contaminated with oxygen at levels of up to 0.4% together with carbon dioxide and acetic acid. The steam produced is highly corrosive. As a result, the materials of construction are a major consideration. The injection of ammonia has been proposed but considerable research is required for system development.

In Canada, the "once-through oil field steam generator" which produces 80% quality steam, has become the industry standard for in-situ recovery operations. The high pressure, superheated, 99% quality steam is seldom, if ever, used in the recovery operation because of the stringent feedwater quality requirements. Table 2 gives the specifications for the feedwater quality required for the once-through and for the Thermosludge steam generators.

The Thermosludge steam generator is an integrated water treatment and steam generation process. The process requires little pretreatment beyond some oil removal. Depending on the feedwater composition, chemical additions may be required to ensure complete precipitation of contaminants in the stripper section of the unit. The unit can operate on TDS levels up to 20,000 mg/L and unrestricted silica levels.

Although the Thermosludge process has been considered a commercially demonstrated process since the mid 1960's, the process has never gained the widespread commercial acceptance that the conventional once-through steam generator has enjoyed in Canada. The main reason for the disfavour appears to be economic rather than a technical concerns. Although water pretreatment costs are reduced, in the Thermosludge process, the capital and operating cost increases as the steam generating capacity increases. Secondly, most units operate at 10-15 percent lower thermal efficiency than the conventional units. Finally, most of the Thermosludge steam generators in North America operate at 5.5 to 7.6 MPa pressure range. There is very limited operating experience at higher 10-14 MPa pressure range.

The prime requisite of feedwater quality for the once-through steam generator is oil-free, zero hardness, low-silica, low-salinity feedwater. Since the unit is designed to produce 80 percent quality steam, it is capable of handling feedwaters with relatively high concentration of dissolved solids. The remainder of this paper discusses the technology for the treatment of produced water to meet the feedwater quality requirement for the once-through steam generators and the limitations of water treatment processes and equipment.

PRODUCED WATER TREATMENT TECHNOLOGY

The technology for the treatment of produced water to meet steam-generator feedwater specification is still in the development stage. Despite previous of experience, many produced water treatment systems continue to encounter operating problems some related to mechanical design and others to materials of construction.

Figure 1 shows the schematic of a typical process train to treat produced water for once-through generators. The process train consists of a skim tank for gross oil removal, induced gas flotation and deep sand filter for secondary oil removal, hot lime softener and anthracite filters for silica and hardness removal followed by secondary polishing softeners for final hardness removal.

■ Oil Removal

Specifications for feedwater quality dictate that the feedwater should be essentially free of oil before entering the once-through steam generator. The industry standard is 1 mg/L or less in the feedwater to the boilers. Although higher concentrations have been recorded without adverse effects on boilers, the lower concentration minimizes development of corrosion or coking in the boiler and fouling of ion exchange resins.

Common practice in the industry is to remove gross oil by skim tanks followed by induced gas flotation (IGF) and filtration. Several operators also utilize dissolved air flotation (DAF) process, however, the industry standard is the IGF system.

Skim tanks are designed to provide a quiescent environment for free oil to rise to the surface where it is recovered. Typical oil concentrations in the effluent from a skim tank range from 50 to 200 mg/L. Recent experience on skim tank performance shows that not only are the retention time and free surface area important in the design of the tank but area to depth ratio and configuration of internal baffles also play significant roles in the oil separation efficiency of the tank.

Fine oil and oil-wetted solids from produced water is removed by gas flotation process. The principle involves the generation of fine gas bubbles which attach to oil droplets and particles causing them to rise to the surface where they are skimmed off. The induced gas flotation type units use turbines or jet/inductor type mechanisms for generating fine bubbles. The retention time in the unit is approximately 30 minutes and the units produce effluent with oil concentration in 5-20 mg/L range.

Deep bed sand filtration is normally used as a polishing vehicle for removing residual free oil from the effluent from IGF units. The fixed bed sand filters have been particularly successful in achieving low effluent oil concentrations (less than 5 mg/L). However, the filters are difficult and costly to operate. The main problems stem from binding of the media and the inability of filters to cope with ocassional surge in inlet oil concentrations. Media fouling occurs due to ineffective backwashing procedures.

Recent developments in the removal of residual oil concentrations include upflow coalescing filters with sand media and downflow units utilizing crushed walnut shell media. Both systems are in service at Alberta produced water treatment installations.

■ Hardness and Silica Removal

Deoiled IGF effluent water can be subject to direct softening for hardness reduction or, when warranted, to lime softening for simultaneous reduction of hardness and silica contents.

In direct softening, water is softened directly by ion exchange while any minor oil fouling of the exchange resin is eliminated during backwashing by the addition of surfactant. This approach is successful for produced water with relatively low silica levels, and can be adopted in cases of low steam quality and boiler pressure requirements. In Alberta, Canada, silica levels are high and, even allowing for dilution with fresh water makeup, silica levels in water treated by direct softening would generally exceed the allowable boiler feedwater limits.

At the Shell Peace River Facility in Alberta, Canada, deoiled produced water is blended with river or lake water and treated with strong acid ion exchange for hardness reduction. The process as noted above does not remove silica as does the hot lime softening process. There is a potential that the high levels of silica may reduce the tube life in the injection boiler. When silica levels exceed 60 mg/L the quantity of produced water in the blend is reduced.

Currently, the most effective method for the removal of silica from dilute brines is hot lime softening. The operating temperature of the process dictates the extent of hardness and silica reductions. Cold lime softening process, which operates at about 30°C, can bring the hardness level down to approximately 100 mg/L as $CaCO_3$ but with marginal silica reduction. Hot lime softening at an operating temperature of 100°C to 115°C can achieve hardness levels of 5 to 20 mg/L as $CaCO_3$ and silica concentration of 2 to 5 mg/L. Warm lime softening which operate between 60°C to 90°C, yields an effluent with hardness and silica concen tration levels between cold and hot lime softening.

The reduction of silica is generally considered to be achieved by precipitation and adsorption of the magnesium hydroxide floc. Iron and heavy metals are also precipitated and trace quantities of sulphides are also removed. The partially softened and desilicised effluent is gravity filtered through anthracite media.

■ Secondary Softening

The residual hardness remaining in the hot process softened water is eliminated in the secondary softeners using weak acid ion exchange resins. Both weak and strong acid resins are used in softening produced water to less than 1 mg/L residual hardness. Strong acid resins are used for removing hardness from water low in dissolved solids. Weak acid resins have been used in softening produced water containing up to 20,000 mg/L of TDS.

■ Capital and Operating Costs

Reliable cost data have not been published by the operators of the Canadian produced water treatment plants. In-house cost files developed by Monenco for a 38,000 m^3/d produced water treatment facility using hot lime softening process trains give a treatment cost of $1.40 to $2.00 per m^3 of produced water in 1987 dollars. Estimated costs reported by Owen and Humenick (1986) indicated a wastewater treatment cost of $2.41 (1987 dollars) per m^3 of treated water based on hot lime soft ening. It should be noted that the above costs are "order of magnitude" estimates only. In practice the costs could vary substantially depending on the composition of raw produced water, specification of the treated water, location of the facility etc.

EXISTING CANADIAN PRODUCED WATER TREATMENT PLANTS

Currently there are four produced water treatment plants operating in Alberta, Canada which treat the produced water for reuse as feedwater to the oil field steam generators. In addition, there are several plants which treat the produced water for deepwell injection only.

Table 3 shows the treatment processes employed in treating produced water at the four commercial produced water treatment plants built to date in Canada. As may be expected, there are some similarities amongst the processes employed at the four plants. All plants use primary oil removal step followed by secondary removal of oil and final polishing in a filter. At the Wolf Lake Oil Sand Facility in Alberta, IGF units were substituted for dissolved gas flotation units to provide comparitive data. While the Esso plant at Cold Lake uses hot lime softening to remove gross hardness and silica before cation exchange, the BP Wolf Lake and Suncor facilities use warm lime softening for the same purpose. The Suncor facility also blends treated municipal effluent from a nearby township with the produced water to reduce silica and TDS levels. The Shell Peace River plant relies on direct ion exchange for the removal of gross as well as trace hardness.

The design of filters for removing last traces of oil and suspended solids also varies between various plants. Generally, filters are deep bed types with a bed of 0.5 mm sand, although dual-media and crushed walnut shells are also being used at some locations. Some of the smaller plants treating water for deepwell disposal also utilize cartridge type filters for the final polishing of the effluent.

While no specific mention is made of dissolved organics and other toxicants in produced water either for deepwell injection or steam production, it should be noted that these contaminants are gaining attention. If left unabated there is a potential that they may contaminate groundwater as they are known to migrate over a long-range.

Newer, alternative and improved technologies are also being tried out. These include plate separators, coalescers, cross-flow membrane filters,microfilters, ultrafilters, etc. for oil removal; ion exchange and activated alumina for hardness and silica removal, and eva poration processes (multi-stage flash evaporation, vapour compression), membrane processes (reverse osmosis, electrodialysis) and freeze desali nation for dissolved solids removal.

The technology to treat produced water to a desired end quality has been successfully demonstrated in the Canadian oil fields. The variation in produced water quality and its desired end use necessitates that each plant be custom designed to meet its particular circumstances. There is no doubt that in most cases the removal of silica and hardness governs the type of treatment employed. At some plants this problem has been tackled by using either treated sewage effluent or surface water supplies to dilute silica concentrations. Although treatment costs still remain high, alternative technoligies currently being piloted in Alberta are expected to reduce the operational problems and hence the overall treatment costs.

REFERENCES

- Owen, Thomas E., and Humenick, Michael J., 1986. "Cost Analysis of Water Pollution Control During In Situ Production of Bitumen from Tar Sands" In-Situ, 10(2), 1986.

Table 1
Produced Water Characteristics

Parameter	Units[1]	Monenco In-House	Environment Canada
Calcium	as Ca	25-120	0-2100
Magnesium	as Mg	2-150	2-250
Sodium	as Na	1100-30000	500-36000
Potassium	as K	110-300	11-880
Total Alkalinity	as $CaCO_3$	80-500	0-1300
Sulphate	as SO_4	10-200	0-850
Chloride	as Cl	2000-5000	85-42500
Nitrate	as N	0-4	0-3
Silica Reactive	as SiO_2	100-150	)
			)2-300
Silica Colloidal	as SiO_2	0-150	)
Total Hardness	as $CaCO_3$	70-500	0-10200
Total Dissolved Solids	---	3000-9000	2300-77000
Suspended Solids	---	111-530	0-2000
Tubidity	NTU	0-150	---
pH	---	6-8	6-9
Conductivity	mMHOS	1800-65000	---
Iron	as Fe	0.1-2	0-50
Manganese	as Mn	0.7-6	---
Oil and Grease	---	50-16000	0-44000
Temperature	°C	80-95	21-91

[1] All concentrations in mg/L except where noted.

Table 2
Feedwater Quality Requirements

	Maximum Allowable Concentration (mg/L)		
	Thermosludge[1]	Once-Through[2]	
Parameter	Manufacturers	Combustion Engineering[3]	Monenco
pH	8-11	9-12	8.5-9.5
Total Hardness (as $CaCO_3$)	2000	0.5	0.1
Total Dissolved Solids (TDS)	20,000	7,000	10,000
Total Alkalikityy (as $CaCO_3$)	-	2,000	200[4]
Silica (as SiO_2)	300	150	100
Dissolved Oxygen (as O_2)	-	0.05	0.005
Oil	250	1	1
Suspended Solids	1,000	1	1
Trace Elements (Al, Ba, Cu, Fe, Mn)	-	0.5	0.05
Sulphate (as SO_4)	-	-	)5,500
Chloride (as Cl)	-	-	)
Sodium & Potassium (as Na)	-	-	3,600

[1] 100% steam quality, 14 MPa.
[2] 80% steam quality, 14 MPa.
[3] Personal communication between Combustion Engineering Superheaters Ltd. and Mr. V. Westlake of Monenco Consultants Ltd. (1982).
[4] Sufficient alkalinity to maintain silica in solution.

Table 3
Treatment Processes at Commercial Produced Water Treatment Plants in Canada

Process/Technology	Esso Cold Lake	BP Wolf Lake	Shell Peace River	Suncor Bonnivlile
Skim Tank	x	x	x	x
IGF	x	x	x	x
Deep Bed Coalecers	x	x		
Deep Bed Filters	x		x	
Softening:				
Hot Process	x			
Warm Lime		x		x
Filtration	x	x		x
Weak Cation Softening	x	x		x
Sodium Zeolite Softening			x	
Make-up Water:				
Treated Sewage Effluent				x
Surface Water	x	x	x	

Figure 1
Produced Oil/Preoduced Water Treatment Over-all Treatment Schematic

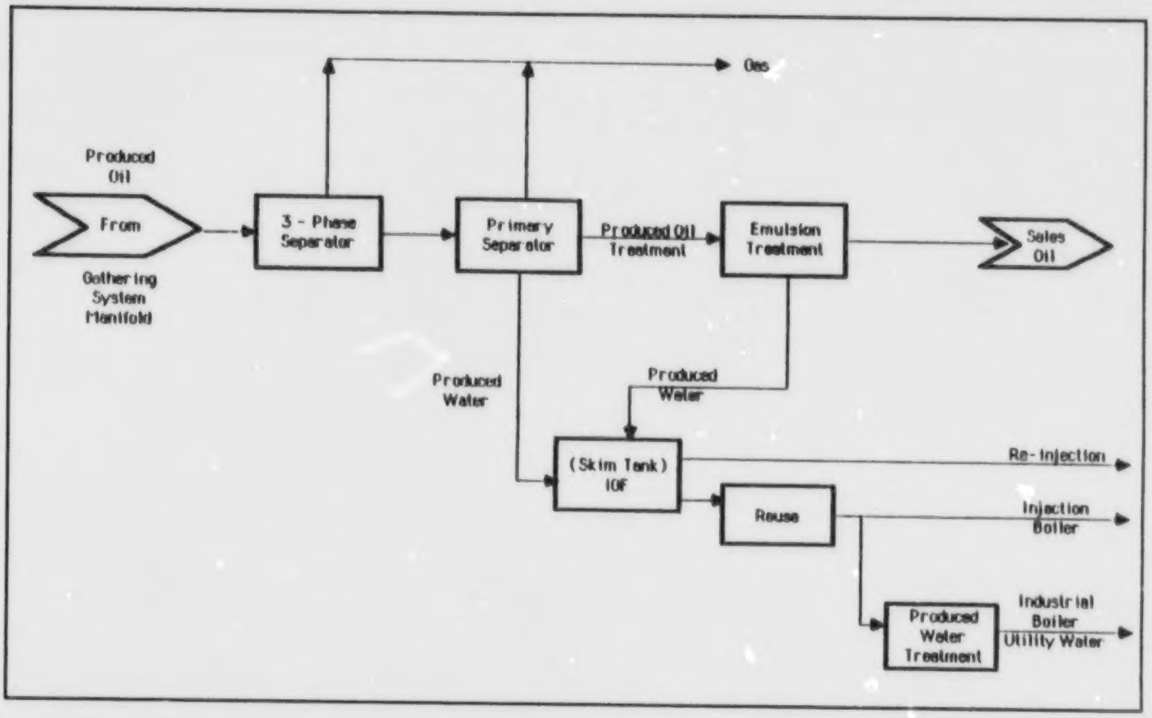
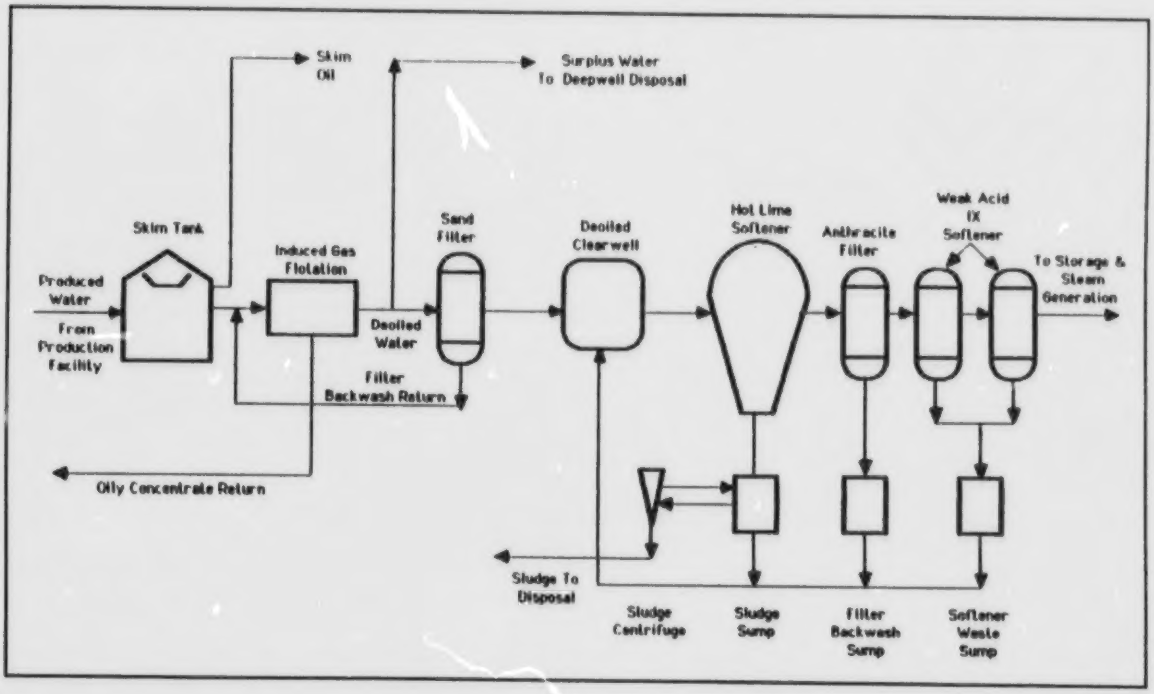

Gas
Produced Oil
From
Gathering System Manifold
3 - Phase Separator
Primary Separator
Produced Oil Treatment
Emulsion Treatment
Sales Oil
Produced Water
Produced Water
(Skim Tank) IOF
Re-injection
Reuse
Injection Boiler
Produced Water Treatment
Industrial Boiler Utility Water

Figure 2
Produced Water Treatment Process Flow Diagram


Skim Oil
Surplus Water To Deepwell Disposal
Skim Tank
Produced Water From Production Facility
Induced Gas Flotation
Sand Filter
Deoiled Water
Filter Backwash Return
Oily Concentrate Return
Deoiled Clearwell
Hot Lime Softener
Anthracite Filter
Weak Acid IX Softener
To Storage & Steam Generation
Sludge To Disposal
Sludge Centrifuge
Sludge Sump
Filter Backwash Sump
Softener Waste Sump

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PROJECT MANAGEMENT OF A HEAVY OIL RECOVERY PILOT

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The development of nonconventional heavy oil deposits (defined in this paper as crude oil deposits which will not flow through the reservoir without external stimulation) requires special skills and expertise which usually are not available among the personnel attached to most conventional petroleum production organizations. This difficulty can be overcome by a special form of organization which, it is felt, could successfully evaluate a heavy oil reservoir. Before outlining this proposed management approach, it may be helpful to briefly describe the usual crude production organization.

The conventional petroleum producing industry is well established with most successful companies having evolved an effective organization for exploring their land holdings and developing their reservoirs. A typical company would have an exploration department which could incldde a land acquisition group, a geological team, a geophysical section, and possibly an exploration drilling department. After the exploration department, through successful "wildcat drilling," has found and delineated a new medium or light gravity conventional oil reservoir, the responsibility for developing it to a commercial operation is usually turned over to members of the production department which then carry out the drilling and producing operations. The production department generally includes groups which have expertise in the areas of engineering (field construction, well completions, well workovers, well repairs, production operations, and reservoir studies, etc.), drilling, construction (production facilities, roads, crude collection networks, and pipeline and/or shipping facilities, etc.) and operations. It is usual for the early activity in a new discovery to be controlled by the management group in the nearest existing operating field. These people supply personnel and services to the new development until it is such a size that is warrants its own full time management and support group. At that time a new organization is set up and takes over full responsibility for the development and operation of the new field.

The above method, or minor variations to it, for handling new discoveries is an accepted procedure for exploring for and developing new medium or light gravity petroleum reservoirs. However, when heavy oil rather than the desired lighter oil is discovered, significant changes to the above outlined organization and progression of events are usually required. The main consideration is that the management and operating personnel from existing conventional producing operations are not familiar with the characteristics of heavy oil accumulations. Neither are they aware of the procedures which are required to stimulate the reservoir or of the special techniques required to bring the crude to the surface and to handle it there. Further, it is usually true that each heavy oil reservoir is a special case and that development and operating procedures must be specifically developed for each.

The fact that each heavy oil reservoir has unique characteristics emphasizes the need to carefully consider the desirability of carrying out a field pilot to provide answers in regard to the commercial potential of the deposit and also to determine the best stimulation technique for developing, if results warrant, the newly discovered reservoir.

The work to be done in carrying out a field pilot is significantly different from that undertaken in the normal producing operations of a conventional oilfield. In the latter case, the objective is to efficiently produce and market the maximum daily amount of oil for the least cost. Whereas with a heavy oil pilot, the main objective is to gather data and make predictions of reservoir performance. It should be possible to analyze pilot information to determine appropriate well spacing, volumes of heat or solvent to be injected, equipment requirements, operating procedures, projected development and operating costs, etc.

The successful operation of a pilot requires individuals with a high level of technical expertise, good analytical abilities, and the capability for developing innovative approaches to problems and opportunities. This type of person can best design the field experiment and correctly analyze the potential for a future heavy oil development. It is felt, further, that the maximum benefits from a field pilot will be realized by assigning to it personnel who have an interest in research and experimentation rather than people who are normally involved in more routine operations.

After an exploration program has discovered and outlined a heavy oil deposit, which contains sufficient oil-in-place to be of commercial interest, decisions must be made on whether or not to commit the necessary large amounts of money required for future development.

It is usually is a good idea to carry out a field pilot in order to build confidence and confirm the simulations. Assuming that it is decided that a pilot is warranted, then the formation of an operating team becomes a paramount consideration. As noted previously, it is usual that company personnel in the area are not familiar with unconventional heavy oil deposits and therefore are not the best people to be involved in a heavy oil development. Even with knowledgeable experts involved, it is difficult to carry out a pilot operation which will yield good definitive results.

It has been found that a good procedure (the best?) for carrying out a pilot operation is to set up a project team to be fully responsible for its (the pilot's) design, construction, operation, and analysis. The first most important step is to choose a skilled project leader. Preferably he (or she) will be a scientist or engineer who is a good manager of people and activities and who has a sound knowledge of, and experience in, the various techniques for stimulating and producing heavy oil reservoirs. The leader should be given full responsibility for the project and, it is felt, should be answerable only to the senior administrator of the field organization in which the heavy oil reservoir is located. It is very important that the project leader has the right to make quick operating decisions and that he be able to obtain field services and other help as he feels they are needed.

The project team should have assigned to it, on a full-time basis, sufficient employees to carry out the normal engineering and operating tasks. These people, who could be seconded from another operation or, possibly, newly hired, should all report to the project leader. It is felt that for a small pilot of up to five wells, there should be a full-time technical staff, in addition to the project leader, of at least an operations engineer and a reservoir engineer. This engineering strength should be increased as soon as there are encouraging results and the consequent likelihood of expanded operations. In addition to the engineers, there should be sufficient nontechnical people to ensure reliable operations and the careful gathering of data.

The project leader should have the right to call upon temporary technical assistance as it is needed to carry out tasks which are not full-time assignments. This outside expertise could be required in such areas as geology, construction, well drilling and completion, well workovers and repairs, equipment engineering, operations, etc. These temporary people should take their direction in regard to pilot work from the project leader so that he always is fully in control of, and clearly responsible for, all aspects of the pilot.

When a heavy oil operation is a new endeavor to a company and the designated project leader has not had meaningful heavy oil production experience, it would be wise to retain an experienced outside consultant who has a background of involvement in the engineering and management of heavy oil experimental production operations. The consultant could provide valuable advice to the project leader and would be very useful in (1) providing guidance to the construction team, (2) assisting in the design of an operating plan, (3) assisting in the interpretation of data, and (4) independently, or otherwise, drawing conclusions in regard to the performance of the pilot and the suitability of the deposit for commercial development. It is felt that the use of a consultant would be cost effective as he would help ensure that mistakes (equipment, completions, facilities, operations, etc.) committed by other operators would not be repeated. Also, he would be very effective as a "sounding board" for all of the project leader's ideas. Finally, after completion of the pilot, the consultant could analyze the data, draw conclusions, and provide company management with an independent assessment of the reservoir's commercial potential.

There should always be very good communication among the members of the project team to ensure that all significant factors affecting the planning, construction, and operations of the pilot are known by everyone and are being incorporated into each individual's work. For example, when reported field data appear to be anomalous and confusing to the reservoir engineer, it should be possible for him to check directly with the data gatherers to determine if there have been unusual field activities or other occurences which have not been reported and which could be affecting the data. Also, if everyone is up to date on pilot performance, it is likely that if there was a need to change the operating plan, it would be recognized early and the changes therefore facilitated.

In summary, a field experimental heavy oil pilot should be operated as a separate entity from other field production operations by a dedicated full time project team. The expertise of this team should be augmented, as necessary, by outside personnel who can take care of a work overload situation or supply technical help which is not available within the team. The project team, which may be assisted by an outside consultant, should be responsible for all phases of the field pilot from initial design through to analysis and interpretation of total pilot performance including the drawing of conclusions relative to the commercial potential of the heavy oil reservoir being evaluated.

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ECONOMIC EVALUATION OF HEAVY OIL PROJECTS

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ABSTRACT

Economic evaluations are a key component in determining whether or not a proposed commercial development should proceed, and in determining the make up of the operation. In addition, economic evaluations are important in directing research and development activities required to support the proposed commercial development.

With an economic evaluation of a proposed commercial development, it is possible to determine whether or not a process under development has the potential to be economically viable. In addition, it is possible to determine the major capital and operating cost centers associated with the process, and the sensitivity of the potential commercial economics to these cost centers. Research then can be directed towards those factors that hold the most potential for achieving economic viability and away from those factors that have a minor economic effect.

This paper will illustrate the use of economic evaluations in determining the viability of a proposed commercial development and the use of the evaluations in determining the direction of research and development activities.

INTRODUCTION

Economic evaluations are a key component in determining whether or not a proposed commercial development should proceed, and in determining the make up of the operation. In addition, economic evaluations are important in directing research and development activities required to support the proposed commercial development.

Prior to carrying out an economic evaluation, information obtained from an experimental operation, or information available on a specific process that is proposed for commercial development, must be analysed and used to: predict the performance of the project; engineer and design the equipment and facilities; and to develop the capital and operating costs for the project. Performance and cost predictions must be as accurate as possible to ensure that the economic evaluations will be accurate. Once the required information is available it is possible to carry out an economic evaluation of the proposed commercial development. Economic evaluations may be handled in a number of ways, however there are three approaches that are commonly use to evaluate the economics of a proposed commercial in situ projects, and to evaluate alternatives that may be used. Net present value (net present worth), discounted rate of return, and bitumen supply price for the project are use to establish the economic viability of a project.

Net present value is the cost of buying into 100 percent of the project at a designated point in time. Time value of money is taken into account by discounting the future annual costs and revenues to the present at a specified interest rate.

Using discrete discounting, with all costs and revenues assumed to occur at the end of the year in which they are incurred, the net present value is as follows:

$$NPV = \sum_{t=0}^{N} (R_t - CC_t - OC_t)/(1+r)^t$$

where:

NPV = net present value

N = life of the project

t = time

R_t = total revenue

CC_t = total capital cost in year t

OC_t = total operating costs in year t

r = discount rate

The quantity ($R_t - CC_t - OC_t$) is the net cash flow (NCF) in year t, and;

$$NCF_t / (1 + r)^t$$

is the discounted cash flow (DCF) for year t. Thus, in order to determine the net present value of a project, the total revenue and total capital and operating cost (or the net cash flow) must be established, and a discount rate must be specified.

Net present value should be determined assuming full equity financing for the project. Financing costs, the cost of borrowing capital for investment in the project and interest expenses associated with borrowed capital should not be included.

Net present value is generally determined at a number of discount rates.

Discounted rate of return is the discount rate at which the net present value for a project is zero. Thus, the determination of discounted rate of return is a specific application of the net present value calculation. The discount rate (r) which is the discounted rate of return is determined from the following:

$$\sum_{t=0}^{N} (R_t - CC_t - OC_t)/(1+r)^t = 0$$

and the discount rate (r) is determined by trial and error or by an iterative routine that will converge to the correct value.

As with the calculation of net present value, the discounted rate of return should be determined on 100 per cent equity financing.

The third calculation used for economic evaluations, determination of product supply price, is again a specific application of the net present value calculation. Supply price is defined as the constant average product price over the project life that is required to give a net present value of zero at a specified discount rate.

Revenue in any year is the quantity of product produced times the product value. For an in situ project producing bitumen, the revenue in any year is:

$$R_t = q_t p_t$$

where:

q_t = quantity of bitumen produced in year t

p_t = price of the bitument in year t

The supply price is determined from the following:

$$NPV = \sum_{t=0}^{N} (R_t - CC_t - OC_t)/(1+r)^t$$

Rearranging the expression and setting the NPV to zero, supply price (Sp) is determined from:

$$Sp = \frac{\sum_{t=0}^{N} (CC_t - OC_t)/(1+r)^t}{\sum_{t=0}^{N} q_t/(1+r)^t}$$

As before, the calculation should be made on the basis of 100 per cent equity investment.

In economic evaluations for determining whether or not there is incentive to proceed with a commercial development, royalties and taxes would normally be included as costs associated with the project. Inflation may also be taken into consideration when there is a difference in inflation on various costs or product values. In the example calculations used in this paper, royalties, taxes and inflation are not included.

SAMPLE CALCULATIONS

In order to illustrate the use of the evaluation procedures outlined, the following example has been developed:

Incremental expansion to an existing in situ operation:

Assumptions:

- ☐ *20 year project life*
- ☐ *5 year pattern life*
- ☐ *1 injection well per pattern*
- ☐ *1 production well per pattern*
- ☐ *wells drilled in year prior to production*
- ☐ *initial steam prior to production at 90 days equivalent demand per pattern*

- ☐ *steam:oil ratio at 4.3*
- ☐ *fuel requirement at 5.315 Gj per cubic meter of steam*
- ☐ *bitumen production at 8 cubic meters per well*
- ☐ *costs:*
  - *site preparation $10,000 per pattern*
  - *surface facilities $30,000 per pattern*
  - *injection well $275,000 drilling/completion*
  - *production well $300,000 drilling/completion*
  - *bitumen handling cost at $1.50 per cubic meter*
  - *diluent handling cost at $1.50 per cubic meter*
  - *water treating cost at $1.50 per cubic meter*
  - *fuel cost at $1.50 per Gj*
- ☐ *bitumen value at $107 per cubic meter*

Capital and operating costs, and product value based on above assumptions are developed in Tables 1 to 4. The eeconomic evaluation of the base case incremental expansion is shown in Table 5, with discounted net revenues for the discounted rate of return in Table 5a. Sensitivites of a number of components are evaluated in Tables 6 to 8.

Table 5 gives the net present values and supply prices for the revenue generated and for each of the cost centers identified, and the net present value (discounted) production over the project life.

The inter-relationship of the three concepts is illustrated by the net present value and supply price of the net revenue. The discounted rate of return for the project is reflected by both the net present value and the supply price equaling zero at the determined discounted rate of return. This is further illustrated if Figure 1, with the net present value and the supply price plotted against the discount rate.

The supply price indicates those cost centers having the most influence on the overall economics of the project. In this case, the cost of the patterns has the greatest effect, followed by the fuel cost for steam generation. Supply prices can be developed for each of the individual components that make up the cost centers. From the supply prices, it is then possible to determine the areas where economic benefit may be obtained from research and development aimed at reducing costs.

Tables 6, 7, and 8 give the economic evaluations of the type of sensitivities that may be required to develop a full understanding of influence of each of the cost centers may have on the economic viability of a project. Table 6 shows the influence from an improvement in product price, table 7 indicates the effect of reducing the cost of production wells, and table 8 indicates the effect of an improvement in steam oil ratio. Additional sensitivities can be developed: as an example the effect of additives to steam to improve the steam oil ratio or extend the life of a pattern.

In general, the factors that have the most significant effect on the economics of a project are those factors that affect the amount of production or the value of the products. Operating cost are next in significance, followed by capital costs.

The decision as to whether or not a proposed commercial development or a particular research project should proceed would depend upon the economic criteria established within the company considering the project. Each company would have its own concept of what the value of money is and what the desired discount rate of return should be, and would proceed accordingly.

The costs use in these examples are for illustrative purposes only. Costs for a proposed project should be developed with a much accuracy as possible and should reflect the location and the timing of a proposed project in order to ensure accurate economic evaluations.

Tables 1

Pattern Costs

Assumptions:
- 20 year project life
- 5 year pattern life
- 1 injection well per pattern
- 1 production well per pattern
- costs:
    - site preparation $10,000 per pattern
    - surface facilities $30,000 per pattern
    - injection well $275,000 drilling/completion
    - production well $300,000 drilling/completion

YEAR	PATTERNS DRILLED	PRODUCTION WELLS DRILLED	INJECTION WELLS DRILLED	PATTERN COST ($000)
1	20	20	20	12,300
2	20	20	20	12,300
3	20	20	20	12,300
4	20	20	20	12,300
5	20	20	20	12,300
6	20	20	20	12,300
7	20	20	20	12,300
8	20	20	20	12,300
9	20	20	20	12,300
10	20	20	20	12,300
11	20	20	20	12,300
12	20	20	20	12,300
13	20	20	20	12,300
14	20	20	20	12,300
15	20	20	20	12,300
16	20	20	20	12,300
17	0	0	0	0
18	0	0	0	0
19	0	0	0	0
20	0	0	0	0
21	0	0	0	0

Tables 2

Bitumen Production

Assumptions:
- wells drilled in year prior to production
- bitumen production at 8 cubic meters per well
- bitumen value at $107 per cubic meter

YEAR	PRODUCTION DRILLED	PRODUCTION WELS OPERATING	PRODUCTION CU. METERS PER DAY	ANNUAL PRODUCTION CU. METERS	BITUMEN VALUE ($0000
1	20	0	0	0	0
2	20	20	160	58,400	6,249
3	20	40	320	116,800	12,498
4	20	60	480	175,200	18,746
5	20	80	640	233,600	24,995
6	20	100	800	292,000	31,244
7	20	100	800	292,000	31,244
8	20	100	800	292,000	31,244
9	20	100	800	292,000	31,244
10	20	100	800	292,000	31,244
11	20	100	800	292,000	31,244
12	20	100	800	292,000	31,244
13	20	100	800	292,000	31,244
14	20	100	800	292,000	31,244
15	20	100	800	292,000	31,244
16	20	100	800	292,000	31,244
17	0	100	800	292,000	31,244
18	0	80	640	233,600	24,995
19	0	60	480	175,200	18,746
20	0	40	320	116,800	12,498
21	0	20	160	58,400	6,249

Tables 3

Bitumen/Diluent Handling Costs

Assumptions:

- bitumen handling cost at $1.50 per cubic meter
- diluent handling cost at $1.50 per cubic meter

YEAR	ANNUAL PRODUCTION CU. METERS	BITUMEN HAND. COST ($000)	DILUENT HAND. COST ($000)
1	0	0	0
2	58,400	88	88
3	116,800	175	175
4	175,200	263	263
5	233,600	350	350
6	292,000	438	438
7	292,000	438	438
8	292,000	438	438
9	292,000	438	438
10	292,000	438	438
11	292,000	438	438
12	292,000	438	438
13	292,000	438	438
14	292,000	438	438
15	292,000	438	438
16	292,000	438	438
17	292,000	438	438
18	233,600	350	350
19	175,200	263	263
20	116,800	175	175
21	58,400	88	88

Tables 4

Steam Associated Costs

Assumptions:

- steam:oil ratio at 4.3
- initial steam prior to production at 90 days equivalent
- fuel requirement at 5.315 Gj per cubic meter of steam
- fuel cost at $1.50 per Gj
- water treating cost at $1.50 per cubic meter

YEAR	ANNUAL PRODUCTION CU. METERS	STEAM REQUIRED CU. METERS	FUEL REQUIRED Gjoules	FUEL COST ($000)	WATER TREAT. COST ($000)
1	0	61920	329092	494	93
2	58400	313040	1663741	2496	470
3	116800	564160	2998391	4498	846
4	175200	815280	4333041	6500	1223
5	233600	1066400	5667691	8502	1600
6	292000	1317520	7002340	10504	1976
7	292000	1317520	7002340	10504	1976
8	292000	1317520	7002340	10504	1976
9	292000	1317520	7002340	10504	1976
10	292000	1317520	7002340	10504	1976
11	292000	1317520	7002340	10504	1976
12	292000	1317520	7002340	10504	1976
13	292000	1317520	7002340	10504	1976
14	292000	1317520	7002340	10504	1976
15	292000	1317520	7002340	10504	1976
16	292000	1317520	7002340	10504	1976
17	292000	1255600	6673249	10010	1883
18	233600	1004480	5338599	8008	1507
19	175200	753360	4003949	6006	1130
20	116800	502240	2669299	4004	753
21	58400	251120	1334650	2002	377

Table 5

Base Case Economic Evaluation

YEAR	ANNUAL PRODUCTION CU. METERS	BITUMEN REVENUE ($0000	PATTERN COST ($000)	FUEL COST ($000)	WATER TREAT. COST ($000)	BITUMEN HAND. COST ($000)	DILUENT HAND. COST ($000)	TOTAL COST ($000)	NET REVENUE ($000)
1	0	0	12,300	494	93	0	0	12,887	-12,887
2	58,400	6,249	12,300	2,496	470	88	88	15,440	-9,192
3	116,800	12,498	12,300	4,498	846	175	175	17,994	-5,497
4	175,200	18,746	12,300	6,500	1,223	263	263	20,548	-1,802
5	233,600	24,995	12,300	8,502	1,600	350	350	23,102	1,893
6	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
7	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
8	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
9	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
10	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
11	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
12	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
13	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
14	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
15	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
16	292,000	31,244	12,300	10,504	1,976	438	438	25,656	5,588
17	292,000	31,244	0	10,010	1,883	438	438	12,769	18,475
18	233,600	24,995	0	8,008	1,507	350	350	10,215	14,780
19	175,200	18,746	0	6,006	1,130	263	263	7,662	11,085
20	116,800	12,498	0	4,004	753	175	175	5,108	7,390
21	58,400	6,249	0	2,002	377	88	88	2,554	3,695
TOTAL	4,672,000	499,904	196,800	168,056	31,620	7,008	7,008	410,493	89,411
DISCOUNT RATE:			NET PRESENT VALUE						
0%	4,672,000	499,904	196,800	168,056	31,620	7,008	7,008	410,493	89,411
5%	2,740,237	293,205	133,305	99,286	18,681	4,110	4,110	259,493	33,713
10%	1,732,028	185,327	96,232	63,237	11,898	2,598	2,598	176,563	8,764
15%	1,165,636	124,723	73,237	42,898	8,071	1,748	1,748	127,703	-2,980
20%	826,026	88,385	58,174	30,651	5,767	1,239	1,239	97,070	-8,685
30%	466,999	49,969	40,384	17,630	3,317	700	700	62,732	-12,763
DISCOUNT RATE:			SUPPLY PRICE						
0%		$107.00	$42.12	$35.97	$6.77	$1.50	$1.50	$87.86	$19.14
5%		$107.00	$48.65	$36.23	$6.82	$1.50	$1.50	$94.70	$12.30
10%		$107.00	$55.56	$36.51	$6.87	$1.50	$1.50	$101.94	$5.06
15%		$107.00	$62.83	$36.80	$6.92	$1.50	$1.50	$109.56	($2.56)
20%		$107.00	$70.43	$37.11	$6.98	$1.50	$1.50	$117.51	($10.51)
30%		$107.00	$86.48	$37.75	$7.10	$1.50	$1.50	$134.33	($27.33)

DISCOUNTED RATE OF RETURN = 13.34%

Table 5a

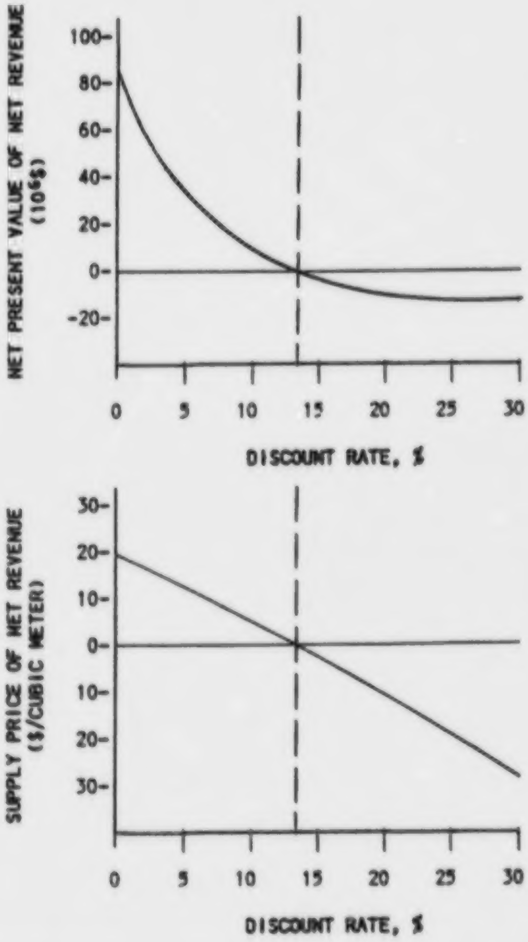
Base Case Economic Evaluation Discounted Rate of Return

YEAR	NET REVENUE ($000)	DISC.CASH FLOW 13.348%
1	-12,887	-11,369
2	-9,192	-7,154
3	-5,497	-3,775
4	-1,802	-1,092
5	1,893	1,012
6	5,588	2,635
7	5,588	2,325
8	5,588	2,051
9	5,588	1,810
10	5,588	1,596
11	5,588	1,408
12	5,588	1,243
13	5,588	1,096
14	5,588	967
15	5,588	853
16	5,588	753
17	18,475	2,196
18	14,780	1,550
19	11,085	1,025
20	7,390	603
21	3,695	266
TOTAL	89,411	0

DISCOUNTED RATE OF RETURN = 13. 335%

Figure 1

Base Case Economics



DISCOUNTED RATE OF RETURN = 13.34%

Table 6

Economic Evaluation

Base case with bitumen value increased to $125 per cubic meter

YEAR	ANNUAL PRODUCTION CU. METERS	BITUMEN REVENUE ($0000	PATTERN COST ($000)	FUEL COST ($000)	WATER TREAT. COST ($000)	BITUMEN HAND. COST ($000)	DILUENT HAND. COST ($000)	TOTAL COST ($000)	NET REVENUE ($000)
1	0	0	12,300	494	93	0	0	12,887	-12,887
2	58,400	7,300	12,300	2,496	470	88	88	15,440	-8,140
3	116,800	14,600	12,300	4,498	846	175	175	17,994	-3,394
4	175,200	21,900	12,300	6,500	1,223	263	263	20,548	1,352
5	233,600	29,200	12,300	8,502	1,600	350	350	23,102	6,098
6	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
7	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
8	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
9	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
10	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
11	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
12	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
13	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
14	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
15	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
16	292,000	36,500	12,300	10,504	1,976	438	438	25,656	10,844
17	292,000	36,500	0	10,010	1,883	438	438	12,769	23,731
18	233,600	29,200	0	8,008	1,507	350	350	10,215	18,985
19	175,200	21,900	0	6,006	1,130	263	263	7,662	14,238
20	116,800	14,600	0	4,004	753	175	175	5,108	9,492
21	58,400	7,300	0	2,002	377	88	88	2,554	4,746
TOTAL	4,672,000	584,000	196,800	168,056	31,620	7,008	7,008	410,493	173,507

DISCOUNT RATE:			NET PRESENT VALUE						
0%	4,672,000	584,000	196,800	168,056	31,620	7,008	7,008	410,493	173,507
5%	2,740,237	342,530	133,305	99,286	18,681	4,110	4,110	259,493	83,037
10%	1,732,028	216,503	96,232	63,237	11,898	2,598	2,598	176,563	39,941
15%	1,165,636	145,704	73,237	42,898	8,071	1,748	1,748	127,703	18,001
20%	826,026	103,253	58,174	30,651	5,767	1,239	1,239	97,070	6,183
30%	466,999	58,375	40,384	17,630	3,317	700	700	62,732	-4,357

DISCOUNT RATE:			SUPPLY PRICE						
0%		$125.00	$42.12	$35.97	$6.77	$1.50	$1.50	$87.86	$37.14
5%		$125.00	$48.65	$36.23	$6.82	$1.50	$1.50	$94.70	$30.30
10%		$125.00	$55.56	$36.51	$6.87	$1.50	$1.50	$101.94	$23.06
15%		$125.00	$62.83	$36.80	$6.92	$1.50	$1.50	$109.56	$15.44
20%		$125.00	$70.43	$37.11	$6.98	$1.50	$1.50	$117.51	$7.49
30%		$125.00	$86.48	$37.75	$7.10	$1.50	$1.50	$134.33	($9.33)

DISCOUNTED RATE OF RETURN = 24.53%

Table 7

Economic Evaluation

Base case with production well drilling/completion costs reduced to $275,000 per well

YEAR	PRODUCTION CU. METERS	REVENUE ($0000	COST ($000)	COST ($000)	TREAT. COST ($000)	HAND. COST ($000)	HAND. COST ($000)	COST ($000)	REVENUE ($000)
1	0	0	11800	494	93	0	0	12387	-12387
2	58400	6248	11800	2496	470	88	88	14940	-8693
3	116800	12495	11800	4498	846	175	175	17494	-4999
4	175200	18743	11800	6500	1223	263	263	20048	-1305
5	233600	24991	11800	8502	1600	350	350	22602	2389
6	292000	31238	11800	10504	1976	438	438	25156	6082
7	292000	31238	11800	10504	1976	438	438	25156	6082
8	292000	31238	11800	10504	1976	438	438	25156	6082
9	292000	31238	11800	10504	1976	438	438	25156	6082
10	292000	31238	11800	10504	1976	438	438	25156	6082
11	292000	31238	11800	10504	1976	438	438	25156	6082
12	292000	31238	11800	10504	1976	438	438	25156	6082
13	292000	31238	11800	10504	1976	438	438	25156	6082
14	292000	31238	11800	10504	1976	438	438	25156	6082
15	292000	31238	11800	10504	1976	438	438	25156	6082
16	292000	31238	11800	10504	1976	438	438	25156	6082
17	292000	31238	0	10010	1883	438	438	12769	18469
18	233600	24991	0	8008	1507	350	350	10215	14775
19	175200	18743	0	6006	1130	263	263	7662	11081
20	116800	12495	0	4004	753	175	175	5108	7388
21	58400	6248	0	2002	377	88	88	2554	3694
TOTAL	4672000	499811	188800	168056	31620	7008	7008	402493	97319

DISCOUNT RATE: NET PRESENT VALUE

DISCOUNT RATE:									
0%	4672000	499811	188800	168056	31620	7008	7008	402493	97319
5%	2740237	293151	127886	99286	18681	4110	4110	254074	39077
10%	1732028	185293	92320	63237	11898	2598	2598	172651	12642
15%	1165636	124700	70260	42898	8071	1748	1748	124726	-26
20%	826026	88368	55809	30651	5767	1239	1239	94705	-6337
30%	466999	49960	38742	17630	3317	700	700	61090	-11130

DISCOUNT RATE: SUPPLY PRICE

DISCOUNT RATE:									
0%		$106.98	$40.41	$35.97	$6.77	$1.50	$1.50	$86.15	$20.83
5%		$106.90	$46.67	$36.23	$6.82	$1.50	$1.50	$92.72	$14.26
10%		$106.98	$53.30	$36.51	$6.87	$1.50	$1.50	$99.68	$7.30
15%		$106.98	$60.28	$36.80	$6.92	$1.50	$1.50	$107.00	($0.02)
20%		$106.98	$67.56	$37.11	$6.98	$1.50	$1.50	$114.65	($7.67)
30%		$106.98	$82.96	$37.75	$7.10	$1.50	$1.50	$130.81	($23.83)

DISCOUNTED RATE OF RETURN = 15.00%

Table 8

Economic Evaluation

Base case with steam:oil ratio decreased to 4.0

YEAR	ANNUAL PRODUCTION CU. METERS	BITUMEN REVENUE ($0000	PATTERN COST ($000)	FUEL COST ($000)	WATER TREAT. COST ($000)	BITUMEN HAND. COST ($000)	DILUENT HAND. COST ($000)	TOTAL COST ($000)	NET REVENUE ($000)
1	0	0	11,800	459	86	0	0	12,346	-12,346
2	58,400	6,249	11,800	2,321	437	88	88	14,733	-8,485
3	116,800	12,498	11,800	4,184	787	175	175	17,121	-4,624
4	175,200	18,746	11,800	6,046	1,138	263	263	19,509	-763
5	233,600	24,995	11,800	7,908	1,488	350	350	21,897	3,098
6	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
7	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
8	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
9	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
10	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
11	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
12	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
13	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
14	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
15	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
16	292,000	31,244	11,800	9,771	1,838	438	438	24,285	6,959
17	292,000	31,244	0	9,312	1,752	438	438	11,940	19,304
18	233,600	24,995	0	7,449	1,402	350	350	9,552	15,444
19	175,200	18,746	0	5,587	1,051	263	263	7,164	11,583
20	116,800	12,498	0	3,725	701	175	175	4,776	7,722
21	58,400	6,249	0	1,862	350	88	88	2,388	3,861
TOTAL	4,672,000	499,904	188,800	156,331	29,414	7,008	7,008	388,562	111,342

DISCOUNT RATE:	NET PRESENT VALUE								
0%	4,672,000	499,904	188,800	156,331	29,414	7,008	7,008	388,562	111,342
5%	2,740,237	293,205	127,886	92,359	17,378	4,110	4,110	245,844	47,362
10%	1,732,028	185,327	92,320	58,825	11,068	2,598	2,598	167,409	17,918
15%	1,165,636	124,723	70,260	39,905	7,508	1,748	1,748	121,170	3,553
20%	826,026	88,385	55,809	28,513	5,365	1,239	1,239	92,164	-3,780
30%	466,999	49,969	38,742	16,400	3,086	700	700	59,629	-9,660

DISCOUNT RATE:	SUPPLY PRICE								
0%		$107.00	$40.41	$33.46	$6.30	$1.50	$1.50	$83.17	$23.83
5%		$107.00	$46.67	$33.70	$6.34	$1.50	$1.50	$89.72	$17.28
10%		$107.00	$53.30	$33.96	$6.39	$1.50	$1.50	$96.65	$10.35
15%		$107.00	$60.28	$34.23	$6.44	$1.50	$1.50	$103.95	$3.05
20%		$107.00	$67.56	$34.52	$6.49	$1.50	$1.50	$111.58	($4.58)
30%		$107.00	$82.96	$35.12	$6.61	$1.50	$1.50	$127.68	($20.68)

DISCOUNTED RATE OF RETURN = 17.02%

43

ECONOMICAL EVALUATION FOR STEAM INJECTION RECOVERY

of the Development Blocks of the Qigu Group, District 9, Karamay Oil Field

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ABSTRACT

Economic evaluation by a thermal recovery program have been performed on eight development blocks from the Karamay Oil Field. The result indicates that the cost for steam injection recovery in the Karamay Oil Field will be higher than that for other oil fields in China. Therefore a government incentive program is needed for the development. Blocks 3, 4, and 6 of the Karamay oil field are profitable when the heavy oil price is double that of the light crude oil.

INTRODUCTION

The steam injection method for recovery of heavy oil in China has achieved a breakthrough in recent years. New heavy oil pools have been put on production on a regular basis. Annual heavy oil production has reached 1.5 million tons in 1986.

The heavy oil reservoirs of the Qi-gu group in District 9 of the Karamay oil field was divided into eight blocks for development based on the reservoir conditions and development efficiency. This paper evaluates the eight blocks from an economic perspective. The results will be used as a basis for decision-making in the development of the heavy oil reservoirs.

BASIS FOR ECONOMIC ANALYSIS

Reservoir Parameters.

The reservoir parameters which were used for the physical and numerical simulation study consists of reservoir lithology, net pay, petrophysical and fluid properties. From the simulation study, the following engineering decisions were made:

- *(1) The injection pattern, well spacing, and the number of injection and production wells;*
- *(2) The production rate and amount of oil and fluid productions at each production stage;.*
- *(3) The duration of each production stage; and*
- *(4) The techniques and facilities required during each development period.*

For convenience, this paper assumes that the well plan, well spacing, and the number of wells are equal for all development blocks. Blocks 3, 4, 5, 6, and 7 were analyzed individually because their net pay, viscosity of the crude oil, and reservoir permeability (Table 1) vary greatly among these blocks. A numerical simulation model was applied to study the production performance and the production rate during the stages of steam stimulation and steamflood operations. The results are summarized in Tables 2 and 3. These results will provide technical information for the future development of the heavy oils within these blocks.

Economic Indexes.

The capital investment for steam injection recovery includes operating costs and other capital investments. The operating cost includes the costs of drilling, the steam feed system, and the production, collection, and transportation systems. The other capital investment refers to the total cost of building work shops, field constructions, administrative and living quarters. In the Karamay oil field, the other capital investment amounts to about 40% of the operating cost investment. The formula then for the other capital investment is:

Other investment (I4) = [drilling (I1) + steam feed system (I2) + production, collection and transportation system (I3)] x 40%.

Therefore, the total investment is expressed as:

Total investment (I) = I1 + I2 + I3 + I4

The cost for steam injection recovery includes: (1) the fuel cost to generate the required amount of steam; (2) the material costs; (3) the costs for generating the power for drilling and well maintenance; (4) the cost for water disposal; and (5) other related costs (Table 4).

METHODS FOR ECONOMIC EVALUATIONS

The aim of economic evaluation is to use a single monetary value as an indicator of the level of profit from a project. Unfortunately, all the evaluation methods can only measure certain aspects of profitability. For example, for questions such as "Which investment is more attractive?" Which investment has a lower risk?" An index that measures the maximum monetary value or maximum profit for the project will be used to answer the first question, and indexes for payout period and the development cost will be used to answer the second question. This paper shall apply eight indices which are commonly used abroad and domestically. These indices are:

Profit to Investment Ratio.

This static index reflects the amount of profit produced per unit of investment. The formula is as follows:

PR = (Total income - total investment) / Total investment

Net Present Value Profit.

This index is a sum of all future cash flow discounted to a particular time (in the development of the project) using a specific discounted rate. The formula is as follows:

$$\sum_{n=0}^{n=0} CEn / (1 + Dr)^n$$

where

CEn = cash flow amount at nth year,

Dr = chosen interest rate.

The index measure whether the project is profitable or not at the chosen interest rate. If NPV is positive, then the project is profitable.

Growth Rate of Return.

This index is also called the profit growth rate and is expressed as:

Growth rate (GR) = $(FW / PW)^{1/n-1}$

where:

FW = future value,

PW = investment amount.

Payout Period.

The payout period is the period from the time of the initial investment to the time when the accumulated net revenue equals the investment, i.e. the length of time required to get the investment capital back. This index is often used to measure higher risk projects. The calculation method is demonstrated by the following example:

Year	Net Annual income	Cumulative income	Note
0	-1000	-1000	Investment amount
1	500	-500	Loss 500 Yuan
2	400	-100	Loss 100 Yuan
3	300	+200	Investment payout, profit 200 Yuan

The payout period (PY) is 2.33 years.

Internal Rate of Return.

The internal rate of return is the interest rate which makes the present value of net receipts equals to the present value of the investments. The formula is as follows:

$$\sum_{n=0}^{n=0} CFn / (1 + IRR)^n = 0$$

where: CFn = amount of cash flow at nth year,

IRR = internal rate of return,

n = length of project in years.

This index is widely used in foreign oil industry.

Investment Efficiency.

The investment efficiency is the improvement of the net present value. It not only has the advantage of

net present value, but also reflects the investment profit. The formula is expressed as follows:

$$IF = NPV / PW$$

where:

IF = Investment efficiency,

NPV (net present value) = Net income,

PW = total investment amount.

Cost of Oil.

This index is commonly used in China. It reflects the value of oil, but cannot take into consideration of the discount of bank interest rate. The formula is as follows:

$$CT = (IA + OC) / OP$$

where:

CT = cost of oil,

IA = total amount of investment,

OC = total operation cost,

OP = total amount of oil produced.

Investment Effect.

This index is also commonly used in China. It reflects the amount of investment required for a project in order to yield a certain amount of production. The formula is as follows:

EF = Investment amount / average annual production capacity

where EI = Investment effect.

ECONOMIC EVALUATIONS

The investment and production cost for each development block was calculated by running an economic evaluation program for thermal recovery on a micro-computer. The eight economic indices discussed in the previous section were calculated for each block. Finally, the blocks were compared in three aspects: investment effect, technical and economical viability, and dynamic economic indices.

Investment Effect.

Construction capital is required to build a plant which has a production capacity of 10,000 tons per year. The investment effect is the amount of investment required for the capital to be used in construction. The investment required for all blocks are within the economical threshold. Because of the poor reservoir conditions, blocks 5 and 7 have the lowest investment effects. On the other hand, block 3 has the best investment effect among all blocks.

Technical and Economical Viability.

This index is static and does not consider the discount rate. Based on our calculations, steam injection is not an economically viable procedure, if the heavy oil price is the same as the light crude oil.

Dynamic Economic Indexes.

The dynamic economic indexes include the net present value, growth rate of return, investment efficiency and internal rate of return. These indexes indicate whether projects are profitable under the present discount rate. Table 6 shows the result of the calculations when based on a discount rate of 10%, and the heavy oil price is two-fold of the light crude oil, all blocks are profitable except blocks 5 and 7.

Sensitivity Analysis.

We can see from Table 5 that a considerable amount of the production cost was allocated to the fuel cost (between 45% to 49%). One way to reduce the production cost, and hence improve the profitability, is to cut down on the fuel cost by using less steam, i.e. increasing the oil to steam ratio, OSR. It is apparent that blocks 3, 4, and 6 are more profitable than blocks 5 and 7 not only because they produce more oil, but also because they have a higher OSR (greater than 0.28). In order to show the sensitivity of OSR to the profitability, the OSR of block 4 was reduced from 0.29 to 0.24, whereas the OSR of block 7 was increased from 0.24 to 0.27, the result of the calculations was summarized (Table 7) as follows:

(1) Block 4 is no longer profitable.

(2) Block 7 is still not profitable.

CONCLUSIONS

❑ *(1) The cost for steam injection recovery system to be operated in the Karamay oil field is higher than other oil fields in China. A government incentive program for the development of heavy oil recovery in the Karamay oil field is therefore needed.*

❑ *(2) When the heavy oil price is double that of the light crude oil, then blocks 3, 4, and 6 are profitable, whereas blocks 5 and 7 are not.*

❑ *(3) The fuel consumption for generation of steam amounts to about 45% of the total cost. The steam consumption must be reduced. The costs of maintenance, adminstration, and scientific research should also be reduced to a minimum.*

❑ *(4) The economic threshold for investments should be according to the quality of the heavy oil reservoir. For example, the threshold for block 5 and 7 should not be the same as block 3.*

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Table 1
Reservoir Parameters of the Blocks in the Karamay Oilfield

Parameters	Blocks				
	3	4	5	6	7
Net pay (m)	18.0	18.0	14.1	18.0	13.9
Net/gross ratio	0.62	0.54	0.70	0.60	0.54
Crude Viscosity (cp)	4000	7800	10000	15000	20000
Permeability (md)	6400	2500	2650	2200	2600
Porosity (%)	33	30	29	29	29
Oil saturation (%)	60	63	62	62	74
Depth (m)	280	310	360	290	235

Table 2
Production of the Steam Injection Performance of the Blocks in the Karamay Oilfield

	Blocks				
	3	4	5	6	7
Steam injection per period (ton)	1800	1800	1800	1300	1800
Production (ton)					
1st period	1956	1405	608	1105	608
2nd period	1268	984	516	733	516
3rd period	1126	966	470	623	470
4th period	896	743	436	603	436
5th period	809	731	419	644	419
Cumultive oil production (ton)	6055	4829	2446	3708	2446
OSR	0.67	0.54	0.37	0.41	0.37
Recovery (%)	18.7	15.0	12.5	11.5	12.5

Table 3
The Production Performance by Steam Flooding for the Blocks in the Karamay Oilfield

	Blocks				
Annual Oil Production (ton)	3	4	5	6	7
Year 1	4920	3360	840	3360	330
Year 2	4920	4560	1700	4560	570
Year 3	3810	3600	2820	3600	810
Year 4	2880	2700	2520	2700	2550
Year 5	2700	2550	2160	2550	3900
Year 6	2610	2400	1950	2400	1440
Year 7	1920	1800	1710	1800	1920
Year 8	1800	1500	1500	1500	1500
Cumulative Production (ton)	25560	22470	15270	22470	13020
Recovery (%)	42.9	47.9	34.5	47.9	22.2
OSR	0.236	0.208	0.212	0.208	0.18

Table 4
Indexes of Operating Cost for Steam Injection Recovery in the Blocks in the Karamay Oilfield

No.	Operating Cost	Brief Description
1	Fuel Cost (S1)	Cost per ton of steam*
2	Material (S2)	(I1 + I2 + I3) x 3.5%
3	Power (S3)	Power cost per well
4	Water disposal cost (S4)	Water disposal cost per ton oil produced
5	Downhole workover cost (S5)	Downhole workover cost per well
6	Others (S7)	(S1 + S2 + S3 + S4 + S5 + S6) x 20%

* The cost of 100 kg of oil as fuel to generate one ton of steam (the cost of oil is based on the oil price).

Table 5
The Operating Cost in Percentage for the Blocks in the Karamay Oilfield

Costs	Blocks				
	3	4	5	6	7
Fuel	46.8	48.5	44.7	49.0	47.1
Material	8.1	8.2	10.7	8.3	9.8
Power	11.8	11.9	12.8	11.9	13.0
Water Disposal	8.2	8.0	7.9	8.0	7.8
Downhole Workover	6.5	6.5	8.9	6.5	9.2
Others	18.5	16.9	14.9	16.4	12.6

Table 6
Comparison of Dynamic Economical Indexes for the Blocks in the Karamay Oilfield

Indices	Blocks				
	3	4	5	6	7
Growth rate of return (%)	18.9	14.5	3.3	12.9	-9.8
Investment Efficiency (%)	101.8	37.9	-39.8	23.4	-83.2
Internal rate of return (%)	43.8	25.6	-4.8	19.3	-18.1
Interest rate (%)	10	10	10	10	10

Table 7
Comparison of Dynamic OSR Sensitivity of the Blocks in the Karamay Oilfield

Block	OSR	Growth rate of Return	Investment Efficiency	Internal Rate of Return
4	0.29	14.5	37.6	25.6
	0.24	9.4	-4.7	7.0
7	0.22	-9.8	-83.2	-18.1
	0.27	0.8	-54.5	-200.0

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FINANCING A HEAVY OIL DEVELOPMENT PROJECT

A CANADIAN PERSPECTIVE

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ABSTRACT

Petroleum and mineral resources projects in Canada are often financed by lenders in a range of full recourse to non-recourse lending, which simply stated, means that the lender has recourse beyond the project to the assets and cash flow of the sponsors to non-recourse where the lender has no call on the assets of the sponsors and the project is the sole source of repayment and security to the lender.

This paper discusses the Canadian perspective of project financing of a mineral or petroleum resource property and what is required of a project sponsor when borrowing funds from a Canadian lender.

In financing production in the petroleum and mineral industries in Canada it is common practice for the lender to be satisfied that all licenses, permits, rights of way and environmental approvals are in place. Additionally, the lender would likely have an independent consulting engineer evaluate the geological and geophysical interpretation of the petroleum deposit and its resulting reserve and recoverable reserve estimates. Project development plans and production profiles are reviewed and independent opinions are provided concerning the economic value of the resources. These and other aspects of project financing are discussed.

INTRODUCTION

The purpose of this paper is to outline some methods that are used to finance a resource development in Canada and to discuss a lender's criteria for financing a project.

The China-Canada Heavy Oil Symposium offers an ideal forum to discuss and examine technological developments from each country on topics in research, reservoir engineering, in situ pilot project design, drilling, production, surface facilities and upgrading. All of these facets are extremely important when evaluating a bitumen or heavy oil deposit for future development. The financing of a resource development in Canada is dependent upon the accumulation and interpretation of all the relevant technologies applied to the project to ensure prospective lenders that the prospect is viable.

This Symposium is an excellent opportunity to share technical knowledge so that both countries can learn from the other's experience in the development of a resource that we both have in common. This philosophy was ably demonstrated by the delegation of petroleum experts from China that presented several learned papers at the AOSTRA Conference in Calgary, Alberta, June 13, 1986. We are indeed pleased to have this opportunity of reciprocating and to be guests in a country that possesses such a long history and promising future.

We wish to draw to your attention that the Alberta Oil Sands Technology and Research Authority (AOSTRA) has many similarities to the Research Institute of Petroleum Exploration and Development (RIPED) in China. AOSTRA was established as a crown corporation by the Government of the Province of Alberta in 1974. The mandate of AOSTRA is principally to promote research and development into the technological methods required for the efficient and economic recovery and processing of crude bitumen and other oil sands products from the oil sands deposits, and the effective recovery of crude oil through the use of enhanced recovery methods.

Dr. D.A. Redford has provided an outline of the AOSTRA in situ projects and the site specific problems of petroleum recovery. Each experimental pilot project has its own unique problems to be solved that are time consuming and costly. The Government of Alberta had recognized that advances in petroleum recovery and upgrading technology could best be achieved by jointly sharing the development project costs with industrial participants. The relationship between AOSTRA and the industrial participant/operator(s) has been very successful in bringing forward feasible solutions for the viable development of a heavy oil prospect. The role of AOSTRA has been extremely important in supporting the individual companies to prove that their petroleum deposit is economically vaable and therefore worthy of sponsoring its full development by project financing, that is the subject of this presentation.

FINANCING ARRANGEMENTS

Project sponsors seeking to finance the development of hydrocarbon resources in Canada are required to satisfy lenders that the technology to be applied for a site-specific development is capable of economically producing the resource as an assurance to the lender. The following is an outline of some of the basic considerations taken by one of Canada's largest banks.

Project Identification and Feasibility

In developing a financing for a typical large-scale energy project, lenders and/or financial advisors review a number of factors which may include:

- ☐ *the sponsor's financial objectives;*
- ☐ *an assessment of the project's viability and debt service capacity;*
- ☐ *the identification of the appropriate form of financing instruments;*
- ☐ *a comprehensive risk assessment including methods to transfer or reduce risk;*
- ☐ *the development of an appropritate financing vehicle to own the assets;*
- ☐ *a review of tax and legal implications; and*
- ☐ *development of a comprehensive financing and syndication package.*

Almost all major projects beginning with a review of the local economy in which the project is located to determine the availability of raw materials; to assess political, business and economic risks; to determine the size of markets and manpower requirements; and to further refine cost estimates. Pre-feasibility studies are reviewed, together with detailed engineering and design studies to define the scale, market, technical and financial investigations that require further research and financial sensitivity analysis. Financial evaluation models are utilized to determine the appropriate level of capitalization and loan security arrangements.

Typical Resource Financing Structures

Figure 1 compares the traditional method of financing a project using the "balance-sheet" approach with a project financing. Under the traditional method, loans are made directly to the project sponsors and not to a vehicle company or joint venture entity which owns the project facilities. Before describing in more detail project financing arrangements, a brief description of some of the more common approaches to hydrocarbon and pipeline financing through joint ventures and guarantees is given below.

Joint Ventures

The joint venture approach involves the several, or joint and several obligation of the sponsors of the project. In this case, each joint venturer finances its percentage participation on its own credit. This concept requires that each sponsor has an undivided interest in the project, is responsible for raising its share of the cost of construction, and for operating its undivided interest in the project. These functions are usually carried out by a corporation jointly owned by the sponsors (the project vehicle) in the same proportions as their participations and which acts as their agent. Financing is arranged in a manner similar to the traditional method outlined in Figure 1.

It is essential in this type of approach that each sponsor be capable of carrying its share of the financing program. Lenders will require assurance that there are no weaknesses which might prejudice the completion of the project and thus delay or impede the flow of funds necessary to assure the coverage of debt service requirements.

Guarantees

Under this financing method, banks or lending institutions would lend to an operating company against a third party guarantee of payment. The guarantor must, of course, have strong balance sheet support to guarantee the obligation. In some cases, government involvement has been sought in this regard. In return for the guarantee, the government or guarantor may obtain an option to purchase a share of the project or take a royalty on the production, in kind or in monetary terms.

THE USE OF PROJECT FINANCING

Fundamental Advantages to Borrowers

Unlike a balance sheet transaction, project lenders may rely solely on the project assets and after-tax cash flows for debt servicing and security as opposed to the sponsors. This may be particularly attractive in cases where a project sponsor's credit is weak or in cases where guarantees can be made available to a project but not to an individual sponsor. Credit may thus become available to a consortium of large and medium-sized companies that may, for many financial or legal reasons, not be available to an individual company. Moreover, off-balance sheet of treatment of debt and rating advantages can also accrue to the benefit of borrowers.

The objective is to design a financial package that reduces the sponsoring companies' risk while presenting the lenders with sufficient credit support. In addition to assuring itself that the overall strength of the borrower is adequate and that it can operate a project, a lender's decision to fund the project centers on the question of project viability.

Features of Project Financing Structures

Several characteristics distinquish a project financing from a conventional balance sheet loan. A project financing could incorporate the following features:

- ☐ *a separate project company or legal entity is established to segregate the assets and cash flow;*
- ☐ *debt financing in the range of 65-80% of the project's costs can be arranged;*
- ☐ *the sponsors do not provide guarantees to lenders for all the risks involved;*
- ☐ *off-take agreements with third parties such as suppliers, consumers and contractors as a foundation support for credit;*
- ☐ *the obligations are limited or non-recourse and may be off-balance sheet to the project sponsors.*

The degree of recourse to the sponsors' credit varies from project to project. However, in most cases, some form of guarantee to complete the project is usually given by the sponsors.

Production Loans

One form of project financing involves the use of production loans or proceeds production payment finacings. This technique was developed in Canada and the United States in the early 1950's to finance the development of hydrocarbon resource projects. In this form of financing, the borrower obtains advances from a lender under a loan agreement, secured by mortgage on the hydrocarbon reserves and a specific assignment of the production revenues.

There is not specific formula for loan lending values. The term of the loan if generally five to eight years although loans for longer terms have been arranged. For resource projects, international bank credits are usually floating rate loans with a margin over the Prime or Base Rate, Certificates of Deposit (CD) or the London Interbank Offered Rate (LIBOR) being subject to negotiation, term and risk.

Oil and gas loans are normally secured by proven producing reserves. Other reserve categories, such as proved developed non-producing, may be incorporated in the technical analysis but their inclusion or exclusion in the lending decision is on a case by case basis. For new resource projects, the loan is established for a development program where the reserves are classified as proven undeveloped, witha high degree of certainty of successful completion. Lenders do not give much weighting, if any, to reserve categories further down the spectrum such as probable or possible reserves.

Technical and Credit Analysis

There are numerous factors which have conventionally been utilized to determine the lending value of a mineral-based production loan. (See Figure 2). To be more specific, lenders analyze the cash flow generated by the project to determine the level of debt that can be supported under reasonable nn easily override the results of any numerical analysis.

Credit Factors

There are several important measures used in typical resource project financing, such as coverage rates, annual debt service and other repayment options that can be established between the lender and the project ponsors.

In sum, there are a multitude of repayment options other than the conventional fixed or blended repayment schedules. Innovative repayment terms can significantly improve the investors' rate of return on the project and provide considerably more financing flexibility.

Technical Considerations (See Figure 4)

☐ *(a) Reserve Base (See Figure 5)*

Because lenders are assuming the reservoir risk in a production payment loan, the use of independent engineering consultants is a prerequisite to developing a loan transaction. As indicated earlier, lenders are cautious in giving any lending value beyond proven developed producing properties and some banks will only lend against *proven producing reserves*.

The other key factors to consider include the reservoir life, the economic life of the field, the concentration risk and the half-life tests.

Normally, lenders will base the lending value over the economic life of the field or until operating costs are not covered. Abandonment may be covered in the loan agreement and may permit the sponsor to cease production if the net present value (NPV) of future production revenue is negative. Usually this period is at least 20 years in duration. It is preferable if the loan repayment can be provided from more than one reservoir and that the loan limit is established by the half-life of the proven reserves. Variations of the half-life tests are permitted under certain circumstances.

☐ *(b) Production Risk*

In many respects, production risk is more important than reserve risk unless production is limited by reservoir performance in the near term. Differences in reserve estimates may not significantly affect the Net Present Value (NPV) of the cash flow but differences in production estimates can.

In assessing production risk, the quality of data is important with emphasis on historical commercial production.

☐ *(c) Technology*

It is necessary to identify the level of technological complexity employed for a project. Experience has shown that new untried technologies have contributed to cost overruns on large-scale projects in Canada. Harsh environmental conditions may lead to disruptions in production or in the efficient operation of transportation systems. Lenders will want independent engineering assessments of the proposed production methods, capital costs and operating factors in dealing with these unknown risks.

☐ *(d) Other Considerations by the Bank Engineer (See Figure 6)*

In addition to the above-mentioned factors, market and price risks, capital cost overruns and operating costs must also be evaluated in determining the ultimate lending value that can be attributed to the project. In some evaluations, price forecasts are not discounted or risk-adjusted to reflect any systematic forecasting bias. In view of the current pricing uncertainty, price and market factors may be risk-adjusted by a higher discount factor, by adjustment of the percentage of net worth lent against or by individually adjusting externally generated variables that determine cash flow.

Project Risks

We have reviewed the methodology of financing a resource prospect in Canada and some of the key features of obtaining a lender's assurance of a project viability. As in any significant prospect there are risks that have to be identified and analyzed. An oil and gas project risk analysis covers at least six major sectors:

☐ *Financial risk*

☐ *Reservoir/Supply risk*

☐ *Regulatory/Government risk*

☐ *Completion/Cost overrun*

☐ *Market/price risks*

☐ *Operator/participant*

It is beyond the scope of this presentation to discuss the details of each of these risk sectors, however it is important to identify their importance.

TECHNOLOGY RISK

For a heavy oil prospect there usually is no "proven" reserve. Instead we often speak of oil in place. To obtain a proven reserve we need to have the demonstrated technology that on that prospect or reservoir the heavy oil can be produced at a profit. As Dr. Redford has indicated this demonstrated technology will change as reservoir conditions change and is not necessarily transferable from one reservoir to another. A lender in order to reduce the risk factor will usually require demonstrated recovery technology for the heavy oil prospect in question.

Demonstrated recovery technology usually proceeds in four iterative steps. (Figure 7) In the first instance a thorough geological and petrophysical evaluation of the reservoir is obtained. On the basis of this evaluation engineering and laboratory studies are conducted and a prospective recovery process in chosen. This recovery concept is field test pilot test. If the results and preliminary economic indicators Calendar Day, Oil Date and Steam/Oil Ratio from this pilot are promising a full scale demonstration pilot involving several patterns and commercial well spacings is planned and executed. The results of this demonstration pilot (usually only the first few years of results are sufficient) then represent the technology base on which a lender may make an evaluation of risk and economic viability of a full scale commercial development. In making this evaluation the lending institute will normally use the services of an independent consultant.

OTHER AVAILABLE CANADIAN PROJECT FINANCING

■ Export Development Corporation (EDC)

EDC provides export financing support by making medium to long-term loans to foreign borrowers at internationally competitive terms to finance Canadian purchases. In addition to these services, EDC also guarantees loans made to foreign borrowers by other financial institutions.

EDC support covers up to 85% of the value of the Canadian goods and services under the commercial contract, with the remaining normally provided by the buyer or his or the exporter's bank. Funds are paid by EDC directly to Canadian suppliers on behalf of the borrower, in effect providing suppliers with cash sales.

■ Direct Loans

The first service which EDC offers is direct loans to foreign borrowers to support individual sales of Canadian products. Financing may be provided on medium to long term credit and is normally used to support project sales or major sales of goods and services. The loan agreement is negotiated between EDC and the borrower, and a disbursement procedures agreement is signed by all parties, including the exporter, specifying the terms for disbursement.

■ Multiple Disbursement Agreements

A variation on this facility is the multiple disbursement agreements loan. This is used where the buyer of a project (who will normally also be the borrower) requires, for planning purposes, that the terms and availability of the funding be assured at an early stage and that these be fixed for the duration of the project prior to the selection of suppliers or the signing of contracts. Normally, there will be several exporters of record involved and, therefore, several disbursement procedures agreements linked with the loan.

■ Lines of Credit (See Figure 8)

Lines of credit are special types of loans in which EDC lends to a bank, to a financial institution in another country which re-lends the money to buyers, or in some cases directly to the buyer of Canadian goods and services. Under this type of facility, the rates, terms, and disbursement procedures are pre-established so that the transaction moves more quickly than with a conventional loan. The line of credit is mainly used for small to medium sized transactions.

The line of credit facility has become increasingly popular, and in 1986 we established or renewed lines of credit and protocols in various countries totalling 2 billion. Loans signed under such facilities during the year totalled about 200 million in 35 transactions.

CONCLUSION

The complexities of financing major projects in Canada can vary greatly between the project sponsors and lenders and, of course, differ from sector to sector. When considering the development of a proven non-producing heavy oil reserve the project sponsors would naturally prefer a non-recourse arrangement on a project financing basis. The lenders are naturally looking for complete risk protection and at least a limited recourse to the project sponsors assets other than those of the project itself. There are several project risks that lenders must check before a decision is taken to financially support the project.

In our opinion one of the most important criteria in project financing is the acceptance of proven technology, whether it be for reservoir stimulation or surface facilities handling produced liquids. it must be recognized that each heavy oil development will differ in nature and likely will require specifically designed technology solutions. These solutions along with a complete engineering evaluation of the reservoir to be developed is the responsibility of the resource development sponsors or owners.

The contribution of petroleum scientists and engineers is of paramount importance when securing project financing, either from private outside lenders, or from internal government sources.

Thank you for your kind attention to this presentation and we hope that we have adequately explained the importance of petroleum scientists in the undertaking of technology development when competing for the financial funding of a resource project.

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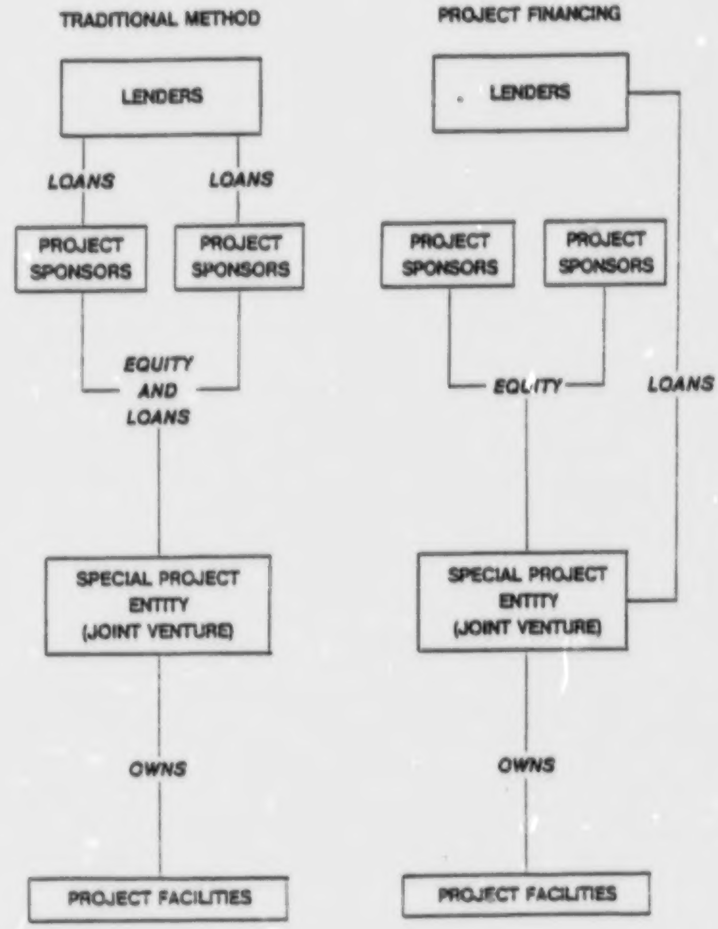
Figure 1
Comparison of the Traditional Method of Financing a Project with Project Financing


TRADITIONAL METHOD
LENDERS
LOANS
LOANS
PROJECT SPONSORS
PROJECT SPONSORS
EQUITY AND LOANS
SPECIAL PROJECT ENTITY (JOINT VENTURE)
OWNS
PROJECT FACILITIES
PROJECT FINANCING
LENDERS
PROJECT SPONSORS
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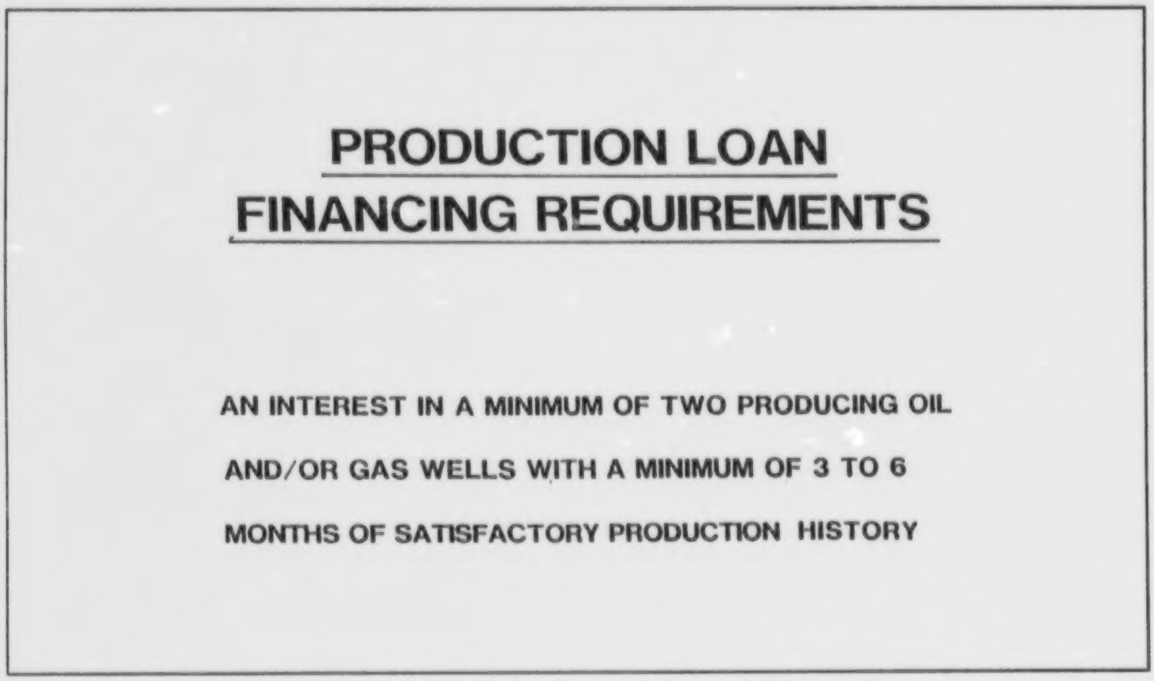
EQUITY
LOANS
SPECIAL PROJECT ENTITY (JOINT VENTURE)
OWNS
PROJECT FACILITIES

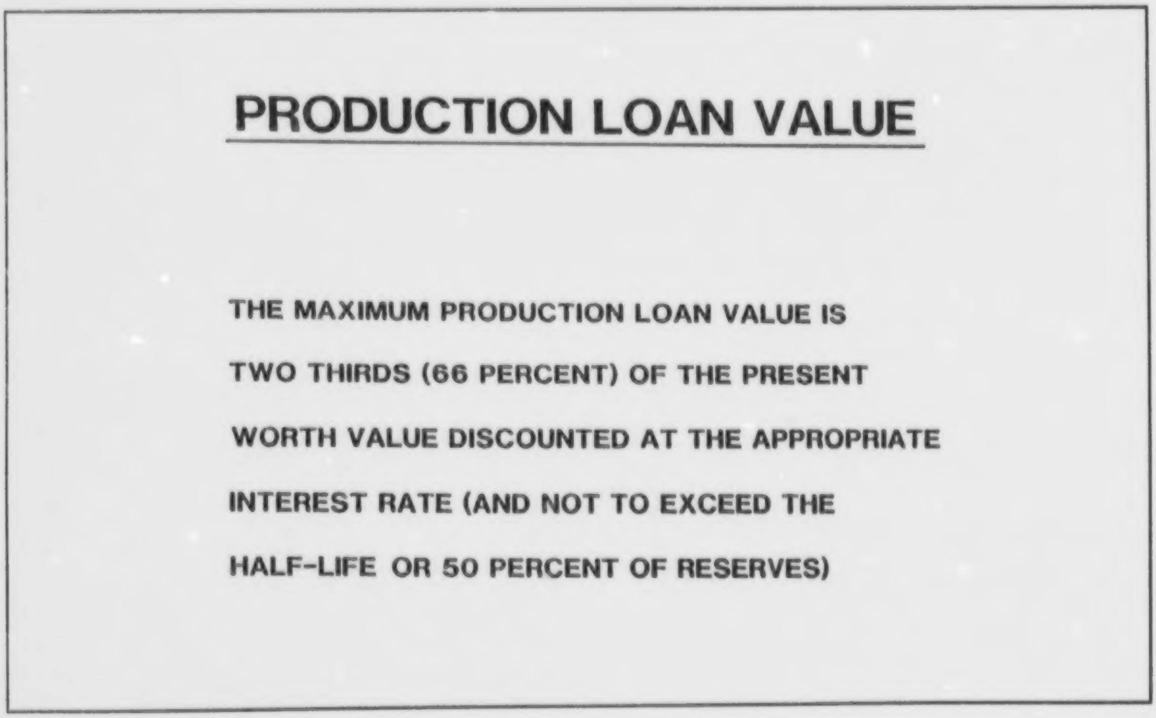
Figure 2



PRODUCTION LOAN FINANCING REQUIREMENTS

AN INTEREST IN A MINIMUM OF TWO PRODUCING OIL AND/OR GAS WELLS WITH A MINIMUM OF 3 TO 6 MONTHS OF SATISFACTORY PRODUCTION HISTORY

Figure 3



PRODUCTION LOAN VALUE

THE MAXIMUM PRODUCTION LOAN VALUE IS TWO THIRDS (66 PERCENT) OF THE PRESENT WORTH VALUE DISCOUNTED AT THE APPROPRIATE INTEREST RATE (AND NOT TO EXCEED THE HALF-LIFE OR 50 PERCENT OF RESERVES)

Figure 4

ENGINEERING EVALUATION REPORT

- DISCUSSION OF THE PROPERTIES AND THE INTERESTS OWNED
- MAP OR TABLE DETAILING TYPE OF INTERESTS, BURDENS, ETC.
- OIL AND/OR GAS-IN PLACE CALCULATIONS
- RECOVERABLE RESERVES AND HOW DETERMINED
- BREAKDOWN OF RESERVES INTO VARIOUS CLASSIFICATIONS
- HISTORICAL PRODUCTION VOLUMES AND REVENUE FIGURES
- YEAR BY YEAR FORECAST OF PRODUCTION VOLUMES, GROSS REVENUES, OPERATING EXPENSES, FUTURE INVESTMENTS, TAX CONSIDERATIONS AND NET REVENUES
- FUTURE CASH FLOWS DISCOUNTED AT VARIOUS INTEREST RATES

Figure 5

RESERVE CLASSIFICATIONS

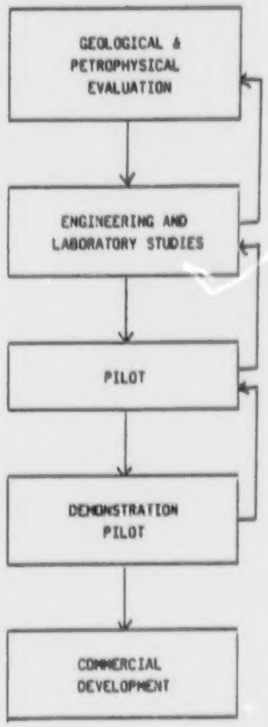
CLASSIFICATION	ACCEPTANCE VALUE
PROVED PRODUCING	TO 100%
PROVED DEVELOPED NON-PRODUCING	50 TO 80%
PROVED UNDEVELOPED	25 TO 50%
PROBABLE	0 TO 25%

Figure 6

CONSIDERATIONS BY THE BANK ENGINEER

- CLASSIFICATION OF RESERVES
- FUTURE MARKET EXPECTATIONS
- OIL & GAS PRICING ASSUMPTIONS
- ROYALTIES AND OTHER GOVERNMENT TAXES
- OPERATING EXPENSES
- FUTURE CAPITAL REQUIREMENTS
- INFLATION RATE ASSUMPTIONS
- TAXABLE POSITION OF THE COMPANY
- APPROPRIATE INTEREST RATE ASSUMPTIONS

Figure 7



DEVELOPMENT OF A HEAVY OIL PROSPECT

GEOLOGICAL &
PETROPHYSICAL
EVALUATION
ENGINEERING AND
LABORATORY STUDIES
PILOT
DEMONSTRATION
PILOT
COMMERCIAL
DEVELOPMENT

Figure 8

CHINA – CANADA

GENERAL FINANCING PROTOCOL

AMOUNT:	$2 BILLION
	CORPORATE ACCT. – $1,650M
	CANADA ACCT. – $ 350M
BORROWER/GUARANTOR:	BANK OF CHINA
INTEREST RATE:	CONSENSUS RATES
	0%
	BLENDED RATE OF 3.0% (APPROX.)
REPAYMENT PERIOD:	
CORPORATE ACCT.	– UP TO 10 YRS. FROM PROJECT COMPLETION
CANADA ACCT.	– UP TO 40 YRS., WITH UP TO 10 YR. GRACE PERIOD

45

PRODUCTION PERFORMANCE OF CONVENTIONAL COLD WATER INJECTION AT GUDAO HEAVY OIL FIELD

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ABSTRACT

The upper Guantao group at Gudao oilfield is an unconsolidated sandstone heavy oil formation. The reservoir was divided and adjusted according to its characteristics for development using areal water injection with small well spacing technique. During the production, formation pressure was kept above oil saturation pressure. As soon as responses to water injection and water breakthrough occurred , pressure differential was appropriately augmented to increase single well liquid production rate. The production performance of the conventional cold water injection method was enhanced by closely coordinating injection and production scheduling, by developing reservoir potential and by employing sand control and emulsification techniques for viscosity reduction.

INTRODUCTION

The No. 3 series of the upper Guantao group at Gudao was discovered in 1968. The main structure of the formation is perfect. The reservoir dips at an angle between 0.5 and 1.5 degree at the top, and between 2 and 3 degree at the flank. It is characterized by the presence of many faults at the south and a regional and uniform water/oil interface.

The upper Guantao formation consists of six sand layers with Guan#3 to Guan#6 being the primary layers. The reservoir is characterized by its high permeability, fluid viscosity and oil saturation. The sedimentary unconsolidated sandstone is highly hydrophilic. The characteristics of the formation is summarized as follows:

☐ 1. *The sedimentary sandstone formation is very permeable and heterogeneous. The permeability is 1.3-2.1* um^2

☐ 2. *The oil bearing formation is at the depth between 1160 and 1315 meters. As it is a loosely cemented formation, sanding is a serious problem during production.*

☐ 3. *Core wettability and permeability tests showed that formation is strongly hydrophilic.*

☐ 4. *Production is high as oil reserve in the formation is concentrated. Among the 20 intervals in Guan No.3 to No 6, the primary six intervals contains 75% % of the oil reserve and their recovery index is 0.014 to 0.02 tons/day.meter.Mpa.*

☐ 5. *The oil is a viscous, low wax content and low pour point asphaltent based crude. At stock tank conditions, oil density is 0.965 and viscosity 250-5,700 mPa/s. At formation conditions, viscosity is 20- 130 mPa.s and the average viscosity is 65 mPa.s. Viscosity is generally low at the top and high at the vicinity of the reservoir boundary. Viscosity in each interval increases with depth. Oil saturation pressure in the formation is quite high, varying from 7.2 to 11.5 MPa. Differential saturation pressure at the surface is small, only 1.5 to 2.0 Mpa.*

The heavy oil reserve at Gudao is estimated to be over 100 million tons. Production of the reservoir began in 1971. In 1973, conventional cold water injection method was used to produce from the reservoir which was initially divided into 6 zones and 10 production units. Only the formation at the Mid #1 area was divided into 2 sets. Since 1981, adjustment was made to increase the production units to 19 with the formations at the major zones of Mid#1, Mid #2 and the West divided into 2 to 4 sets. Production increased 1.5 times after the adjustment and expansion.

PRODUCTION PERFORMANCE BY WATER INJECTION

Analysis of the performance is based on the comparison of the actual production indexes with the theoretical indexes and indexes from other oilfields of similar natures.

i) Increase in Water Content and Cumulative Water/Oil Ratio

At Gudao, the oil is heavy and the oil water mixture is viscous. Water content increased quite rapidly. The situation was significantly improved by better coordination of injection and production, and by adjustment and division of production area and reservoir in 1981. Up until 1985, recovery was 14.12 % and water content was 63.3 %, as shown in Figure 1. Before water content reached 30 %, the increasing rate of water content was high. When the water content was between 30% and 50%, the rate was the same as the theoretical value. Between 50 and 70 % water content. the rate was lower than the theoretical value due to the operational adjustments mentioned earlier. The situation was improving as indicated by the production data in Table 1.

Figure 2 shows a non-dimensional recovery curve of cumulative water/oil ratio plotted against % recovery from the Gudao oilfield actual production data and from pipeflow calculation method*. From this recovery curve and also from the displacement characteristics curve*, cumulative water production is found to exhibit a linear relationship with cumulative oil production. It is possible to calculate cumulative water/oil ratios from these different relationships at a constant recovery of the recoverable oil in place, or vice versa. Results of these calculations are given in Tables 2 and 3, and shown in Figures 3 and 4. Comparison of these calculation results show that Gudao oilfield ultimate cumulative water/oil ratio is between 3.2 and 9.4, which falls between the values from the pipeflow method and the actual production data of a similar oilfield. The results also indicate that at the same cumulative water/oil ratio, recovery efficiency of the Gudao oilfield is in close agreement with the values calculated from pipeflow method and the actual data from the similar oilfield.

ii) Injected Water Utilization And Net Water Influx Ratios

Injected water utilization rate refers to the amount of water injected in proportion to the amount of net water influx to the reservoir at a particular stage of the water injection operation. By comparing the actual injected water utilization rate from Gudao field data with the theoretical values calculated from pipeflow method, it is possible to find out the efficiency of water injection at various operational stages. From Figure 5, it can be seen that, since 1981, the injected water utilization rate at Gudao oilfield is approaching the theoretical values indicating that the water injection operation is increasingly more effective.

Cumulative net water influx rate refers to the cumulative net water influx to the reservoir in proportion to the cumulative water injected. The actual cumulative net water influx rate from the field data is considerably lower than the theoretical values calculated from the pipeflow method during the early period, indicating that insufficient amount of water was injected during the time. As a result of subsequent increase in water injection rate and oilfield operational adjustment, the gap between the actual and the theoretical values becomes increasingly smaller, as shown in Table 4 and Figure 6.

Using the displacement characteristic method* for calculating cumulative water influx rate, the predicted value based on actual field data is 5 to 17 % higher than the theoretical value from the pipeflow method, and also higher than the value from a similar oilfield, as shown in Table 5 and Figure 7. This indicates that the water injection operation is quite effective.

iii) Water Drive Index

Water drive index, referred to as the ratio of net water influx to the total reservoir oil withdrawal, reflects the amount of energy supplement to the formation by the injected water. The previous observation regarding the field being under-injected with water during the early stage was verified by noting that the cumulative and the current water drive indexes from the actual field data were considerably lower than its corresponding theoretical values. Subsequent to the increase in water injection and field operational adjustment in 1976, the cumulative water drive index increased steadily. From 1981 onwards, although the index was still lower than the theoretical value, it basically stayed between 0.66 and 0.7, as shown in Figure 8. The waterflood operation had steadily been improved during this period. Between 1982 and 1984 when cumulative water/oil ratio was high, the current water drive index was lower than its theoretical value; the reverse is true between 1982 and 1984 when the cumulative water/oil ratio was low and when the producing intervals in the formation and well patterns were rearranged. Since 1985, as the water/oil ratio has been approaching the ratio attainable with a stable formation pressure, the gap between the actual and the theoretical values in current water drive index becomes smaller, as shown in Figure 9

■ iv) Injection Pore Volume

The injection pore volume exhibits fairly good correlation with the recovery from the actual field data and also from theoretical calculation using the pipeflow method, as shown in Figure 10. The recovery calculated from these relationships at the same injection pore volume indicates that the actual field value is in good agreement with the theoretical values but they are lower than the values from a similar oilfield (Figure 11 and Table 6).

■ v) Waterflood Invaded Volume

Gudao reservoir is located on an unconsolidated formation. Since no core data were gathered from delineation wells, reservoir information was collected with multiple well logging tools. Since 1983, 186 reservoir interpretation tests on the major oil intervals were conducted at the 48 adjusted wells. Statistics on the interpretation data show a good correlation between water flood thickness coefficient and water saturation. Waterflood volume coefficient was calculated to be 0.7 from the correlation for 1985 when water saturation reached 63.3%. From statistics of well logging for water saturation on the injectors, only 16.5 % of the oil intervals was not affected by waterflood, indicating that the sweeping efficiency of the waterflood process was quite good.

■ vi) Waterflood Recovery

Five methods were used to predict waterflood recovery, as shown in Table 7. During the adjustment period from 1981 to 1985, recovery increased by 5%. The prediction shows that recovery can be increased 2 to 3 % further with additional readjustment between 1986 and 1990, with the ultimate recovery reaching 35%.

DEVELOPMENT AND PRODUCTION IMPROVEMENTS

One of the major strategies for further development of Gudao oilfield was to rezone and readjust oil producing intervals and to decrease well spacing. During early developmental stage, the area was divided into six zones and ten units for development. Only Mid-1 zone consists of two interval sets . In order to deal with high water production, minimize interference between intervals and increase production potential, the major intervals was readjusted in 1981. Mid#1 zone was rearranged to consist of 4 interval sets and both the Mid#2 and West zones were adjusted to consist of 2 sets . Development was further carried out with areal water injection scheme using small well spacing, about 225 to 300 meters between wells. Improvement by the adjustment was noticeable as the degree of control of the waterflood operations reached 90.1% which is an increase of 6.9% over the pre-adjustment period. The increase for the secondary interval was 16.1%.

The second production improvement strategy was to maintain formation pressure at a reasonable level and augment pressure differential appropriately. Since water injection began in 1973, both the formation pressure and well productivity increased noticeably. Water injection was stepped up further since 1977 to maintain formation pressure above oil saturation pressure.

Under the favorable conditions created with water injection operations, pressure differential was augmented in 1977 to increase production by 3,418 tons. This operation involved replacement of pumps on 134 wells and readjustment of 550 wells. Although water content increase by 10 %, a stable production level was able to be maintained in 1977. In 1983, a 7 cm large pump was employed in the very first test involving augmenting pressure differential since the inception of high water production from the major intervals. Production improvement by the large pumps had been quite noticeable for the next several years. The increase in annual production by the large pumps was 68,500 to 100,45 tons, representing a 24.4 to 30.5 % of all the production improvement from the old wells. These two operations in pressure differential augmentation produced a positive impact on production stability and future field development.

Productivity improvement also involved continual adjustment of injecting and producing strategies. Conventional cold water injection for heavy oil production is characterized typically by early water breakthrough, fast increase in water content and short duration in mid and low water production periods. Field experiences at Gudao indicate that these difficulties could be minimized by continual reassessment of injecting and producing strategies. The strategies involved increasing water injection to the low water production intervals while decreasing water injection to the major high water production intervals. For the intervals which already produced high water rate, water injection should be conducted to control direction of water flow. During the period from 1976 to 1985, injection and production were readjusted 114 times at Gudao for controlling the rate of increase in water content and improve production.

Normal stable production was able to be maintained by actions taken to prevent sand production and reduce oil viscosity with water blending. Sand prevention has been necessary in Gudao operations. Several sand prevention techniques are applied now at Gudao. The success rate of these operation is about 72.2 %. Also, by blending heavy oil with a surfactant solution to produce an oil in water emulsion, production of heavy oil with viscosity between 1,000 and 3,000 Pa.s is possible when water content is below 30%.

* *Translator notes: The Terminology is a direct translation from the Chinese version. Reference of the terminology is unavailable in the literatures published in the western world.*

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- 1) Dong X.Z., "Statistical Study on The Production by Natural Water Drive And Waterflood", Petroleum Exploration And Development, 1979, No 6
- 2) Zhang, R., "Evaluation of The Prediction Technique For Waterflood", Petroleum Exploration And Development, 1985 No 4
- 3) Li, X.G., "Development of the Two Types of Reservoir at Gudao", Petroleum Exploration And Development, 1982, No 3

Table 1
Comparison of the Increase Rate in Water Content by Different Methods

Water Content	30	30-50	50-70	70-85	>85
Pipeflow	3.4	6.77	4.94	2.10	1.00
	to 4.28	8.40	6.10	2.76	1.16
Displacement Char	3.47	4.84	4.84	3.47	1.24
Recovery Curve	3.67	4.18	4.02	2.66	1.33
Waterflood Series	3.33	4.23	4.23	3.03	1.08
Similar Oil Field	3.33	4.08	4.08	2.94	1.04
Actual Field Data	8.08	5.93	3.30		

Table 2
Comparison on Cumulative Water Injection/Oil Production Ratio

Recovery, % Recoverable Reserve		60	80	100
Actual Field Data:				
Recovery Curve		1.74	4.04	9.38
Displacement Characteristics		1.24	3.08	8.18
Pipeflow:				
Recovery Curve		1.43	3.89	10.57
	to	2.17	5.41	13.48
Displacement Characteristics		1.88	4.55	11.76
	to	2.03	5.08	13.53
Similar Oil Field		1.45	3.21	7.14

Table 3
Comparison on the Recovery of the Recoverable Reserve

Cumulative Qw/Qo Ratio		0.5	1.0	1.5	2.0
Actual Field Data:					
Recovery Curve		30.30	46.78	56.42	63.26
Displacement Characteristics		36.66	54.98	64.37	70.74
Pipeflow:					
Recovery Curve		27.87	43.05	51.93	58.22
	to	38.99	52.85	60.96	66.71
Displacement Characteristics			42.46	52.83	59.63
	to		43.95	54.55	61.50
Similar Oil Field		28.57	46.36	57.10	64.36

Table 4
Injected Water Utilization and Net Water Influx rates

Recovery Efficiency,%	6	10	14
Water Utilization			
Actual Data	70	47	30
Pipeflow	86-95	49-73	21-42
Difference	16-25	2-26	-9-12
Water Influx			
Actual Data	76	63	50
Pipeflow	94-97	76-89	55-73
Difference	18-21	13-26	5-23

Table 5
Cumulative Net Water Influx

% Recoverable Reserved		40	60	80
Actual Field Data		63.17	41.90	18.71
Pipeflow		49.02	27.44	8.38
	to	50.38	29.47	10.21
Similar Oil Field		46.35	36.95	9.05

Table 6
Comparison on % Recovery

Injection Pore Volume		0.2	0.5	1.0	2.5
Actual Field Data		17.83	25.24	30.85	38.26
Pipeflow		15.94	21.57	26.19	32.30
	to	19.11	26.06	31.32	38.27
Similar Oil Field		18.48	26.70	32.77	41.36

Table 7
Prediction on Recovery from Gudao Oil Field

Method	**% Recovery**
Empirical	30.0-38.2
Pipeflow	30.4-37.1
Relative Permeability	33.3-46.9
Lab Data	32.7-34.8
Dynamic Method	29.2-35.3

Figure 1
Relationship between Recovery and Water Content

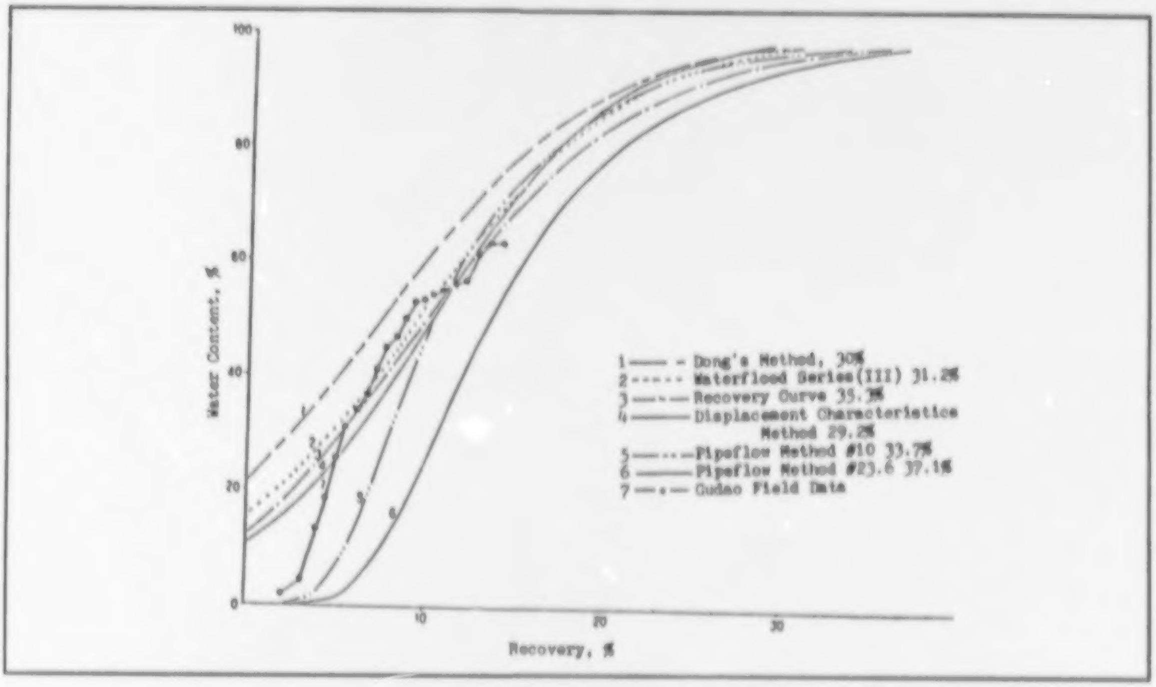


Figure 2
Recovery Curve

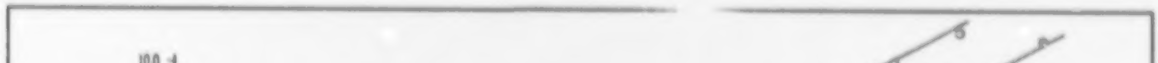


Figure 3
Relationship between Cumulative Water/Oil Ratio and Oil/Water Viscosity Ratio

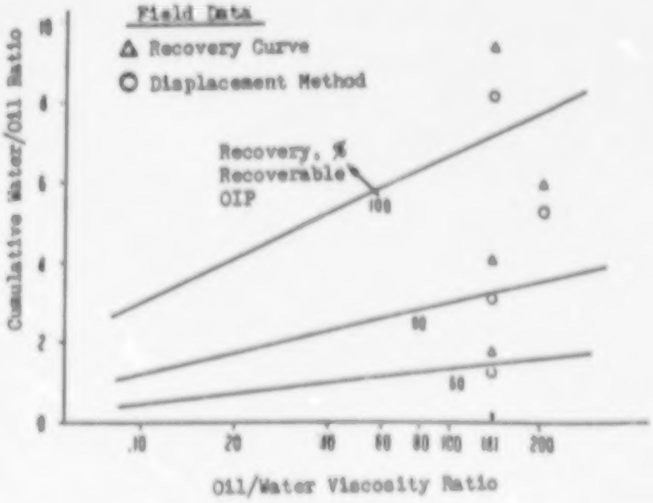


Figure 4
Relationship between Oil/Water Viscosity Ratio and Recovery as a Percentage of Recoverable OIP

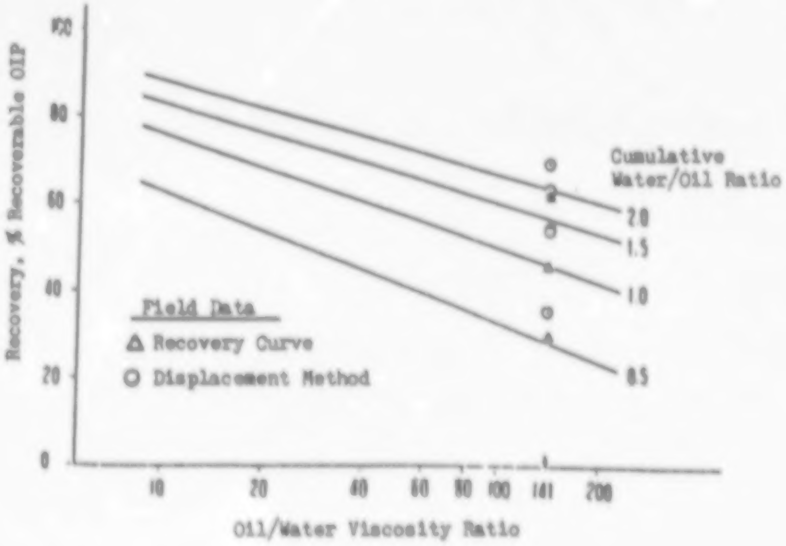


Figure 5
Injected Water Utilization Curve

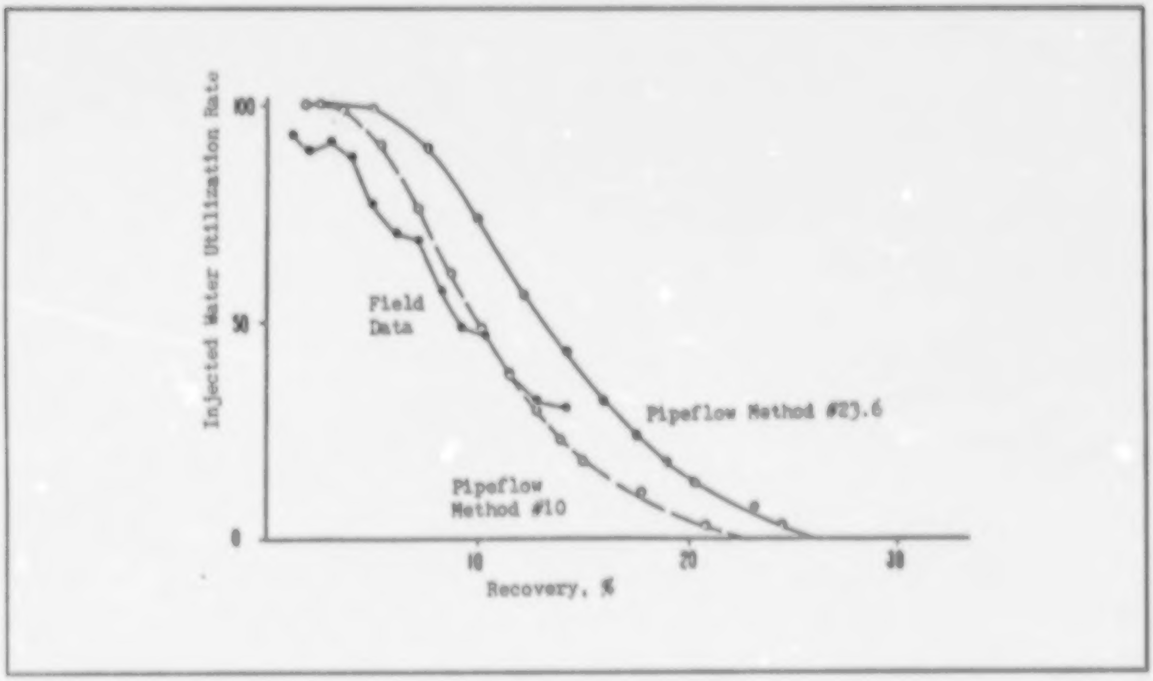


Figure 6
Cumulative Net Water Influx Curve

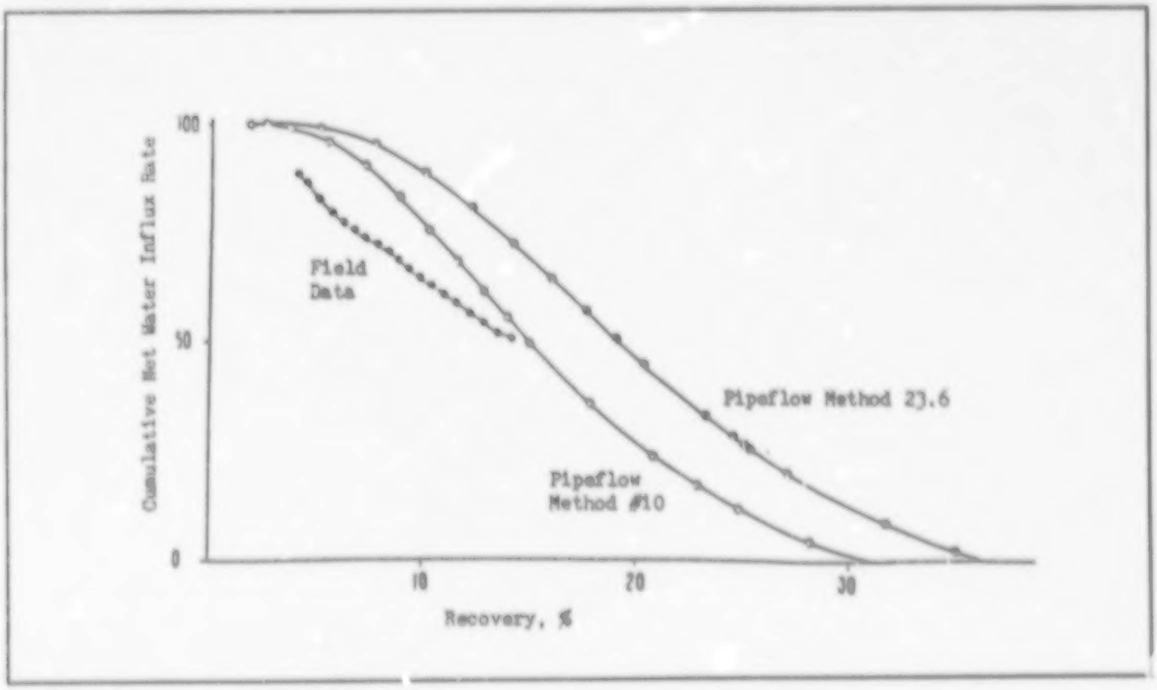


Figure 7
Relationship between Cumulative Net Water Influx and Oil/Water Viscosity Ratio

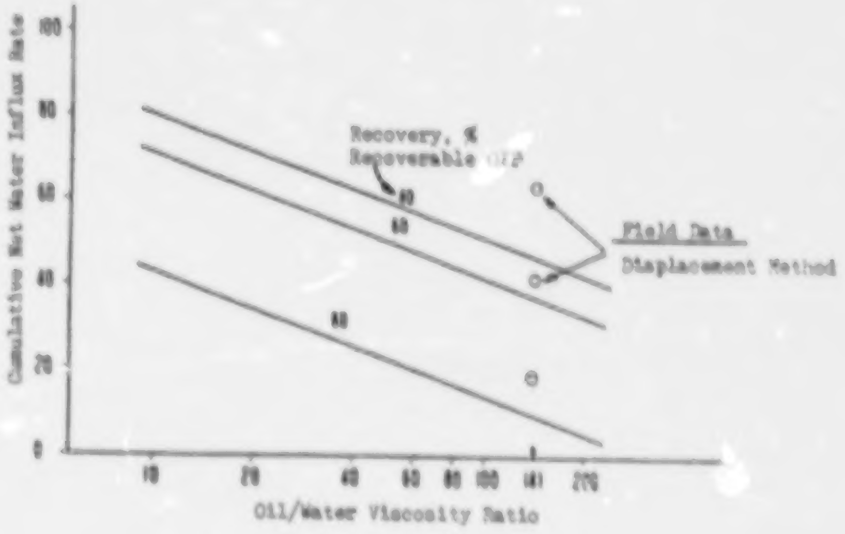


Figure 8
Cumulative Water Drive Index Curve

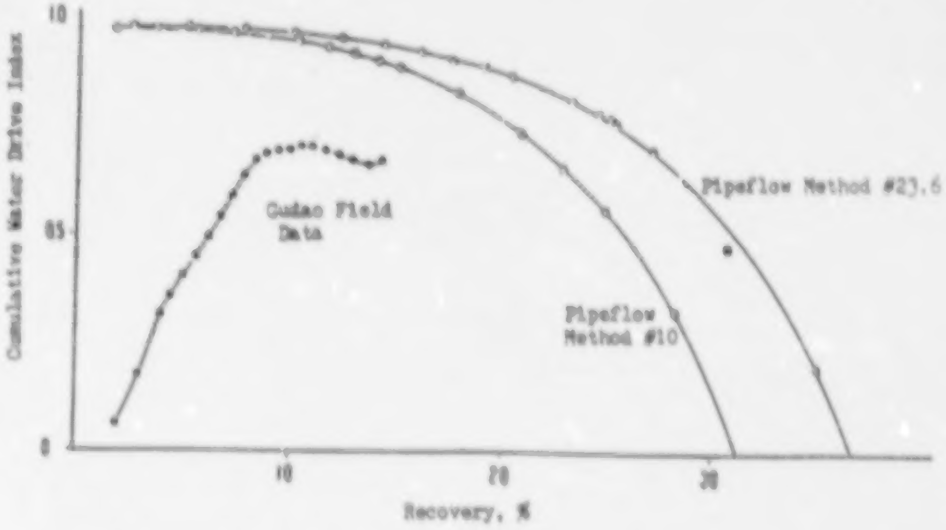


Figure 9
Water Drive Index Curve

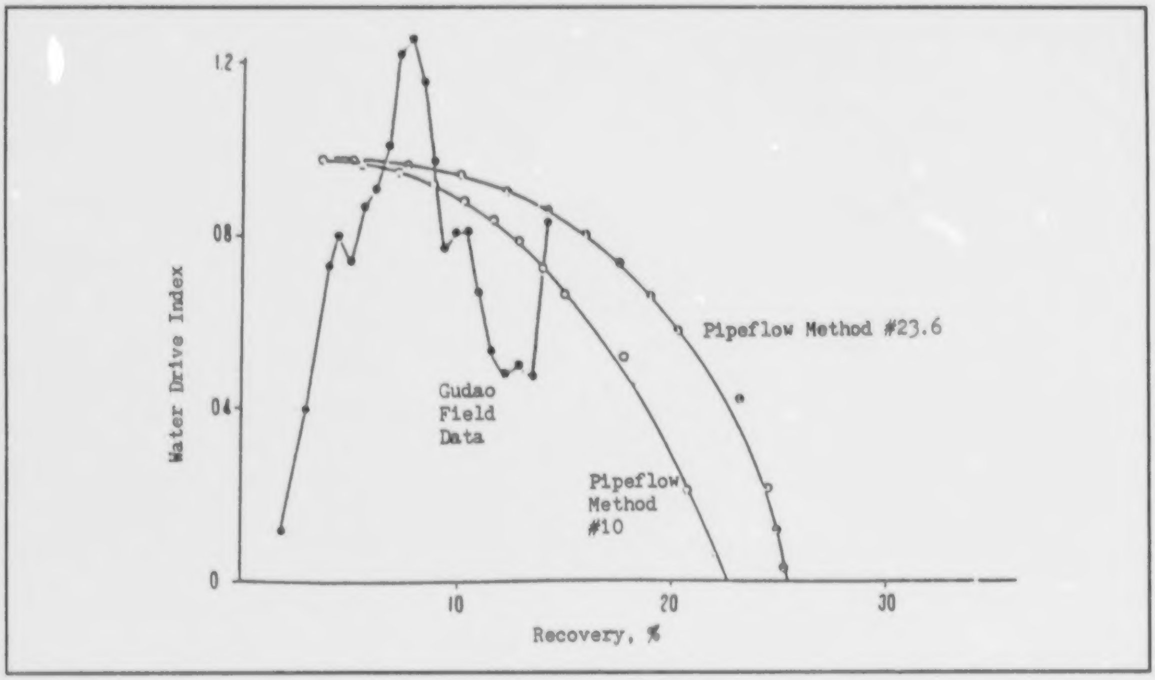


Figure 10
Relationship between Injection Pore Volume and Recovery

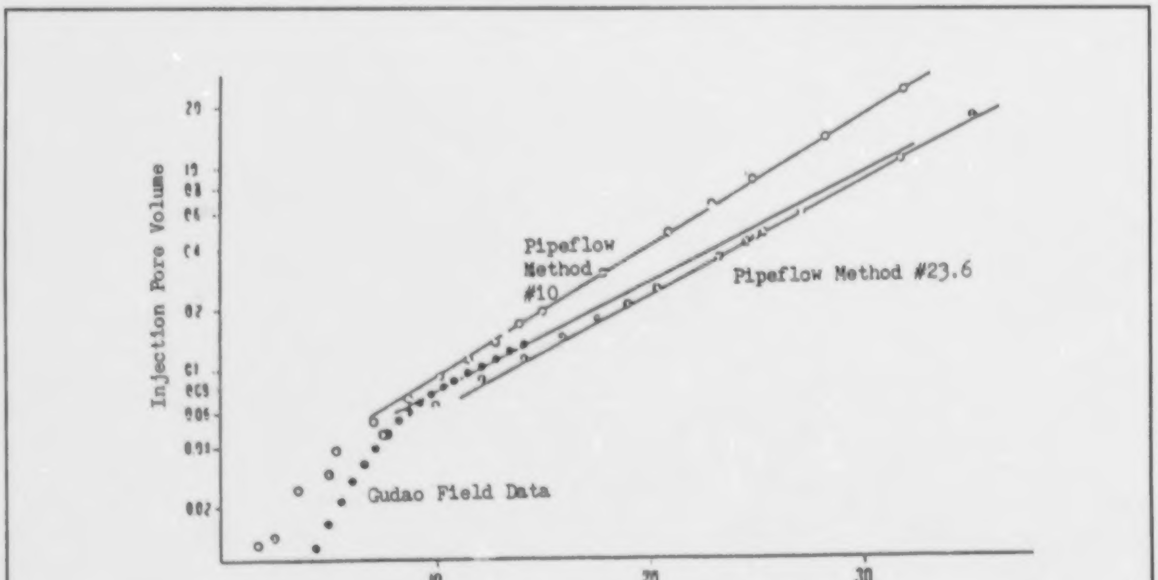
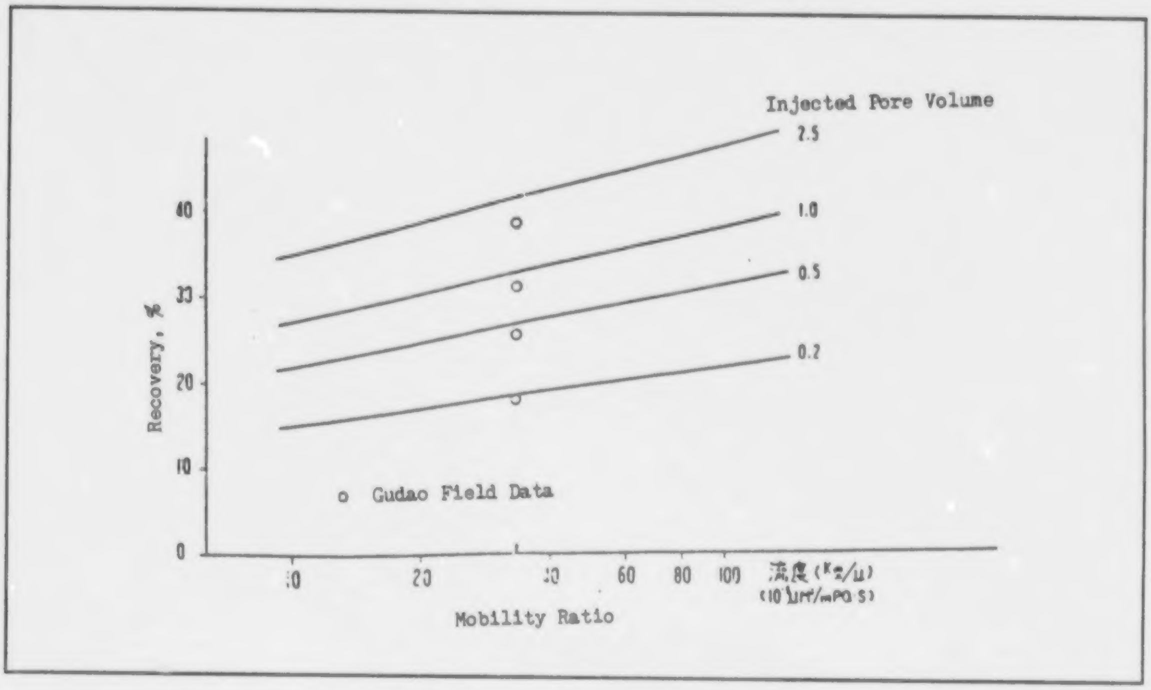


Figure 11
Relationship between Recovery and Mobility Ratio



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RESERVOIR MODEL STUDY OF FIELD SCALE COMBUSTION

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ABSTRACT

A simulation study was undertaken to examine the sensitivities of various important parameters on the dry forward combustion enhanced recovery process conducted on a field scale. Among the reservoir properties studied were pay thickness, permeability variation in the vertical direction and initial oil saturation. Variations in well pattern size and configuration, air injection rates and injection fluid (air or steam) were also examined. To determine the chemical reaction parameters for the simulatins a combustion tube test was matched with the simulator. A technique was devised to model the combustion process in a large field-size grid. It was found that the vertical permeability variation could be modelled adequately with three layers. Results from areal and cross-sectional models were combined to obtain a three-dimensinal analysis of the fire flood performance for each nine-spot field pattern.

Model predictions indicate that there is no technical advantage in using pattern areas smaller than 10 acres for 10 ft. net pay, and 20 acres for 25 ft. net pay. Below these pattern sizes, recoveries of about 40% OOIP and 45% OOIP, respectively, are obtained. Above these pattern sizes extinction of the fire front significantly reduces areal sweeps and oil recoveries, resulting in maximum project lifetimes of about 4.2 years and 10 years for the two pay thicknesses.

Simulation results also show that the vertical sweep efficiency is predominately controlled by the vertical permeability variation in the reservoir, and not by steam or air override effects. The detailed simulator output showed that oil vaporization, cross flow between layers and heat loss to the adjacent formations are important in this thermal recovery process.

INTRODUCTION

The objectives of this study were to derive a data base for the simulation of thermal EOR processes in Lloydminster-type heavy oil reservoirs, and to investigate the sensitivity of oil recovery performance of the combustion process to various parameters. The heavy oil from Lloydminster, Alberta is used in this study.

It was necessary to establish a proper data base for the sensitivity study. Viscosity-temperature data, distillation data and literature references were used to characterize the heavy oil. A combustion tube experiment helped determine an adequate reaction model. The methods and correlations used to obtain the physical properties are discussed in detail.

The sensitivity parameters were divided into three functional categories: model, reservoir and operational parameters. The model parameters arise from the discretization of time and space. Reservoir parameters are specific to the reservoir of interest, and include vertical variations in rock properties and initial conditions.

Practical considerations such as well spacing, pattern configuration and injection and production well specifications comprise the operational parameters. The model parameters were optimized to give a balance of accuracy and economy satisfactory for the study of the reservoir and operational parameters. To reduce computing cost the three-dimensional combustion problem was decoupled into areal and vertical cross-sectional ones, whose sweep efficiencies were then recombined in a consistent manner.

With the optimized model parameters, the reservoir and operational sensitivity parameters were then studied and the results were examined.

In this study all simulations were performed using the Computer Modelling Group's fully-implicit thermal reservoir simulator ISCOM[1].

DATA BASE

Properties of Chemical Components

The oil was divided into a light fraction and heavy fraction. In a distillation analysis of the Lloydminster oil the light fraction, 43% of the total weight, distilled at 572°F. The remainder vaporized by 932°F. Using the normal boiling point (NBP) entries in Table 7(a) of reference 2, these fractions were assigned the molecular weights and specific gravities of the hydrocarbon "groups" C_{17} and C_{37}.

The specific gravity of the heavy fraction was assumed to be 0.98. Using reference 3, the critical properties, thermal expansion, liquid compressibility, gas phase heat capacities and heats of vaporization were calculated from the molecular weight, specific gravity and NBP of each fraction. The heats of vaporization were adjusted to give more realistic liquid heat capacities, and a more accurate gas heat capacity was obtained for the light fraction from reference[4].

A dead oil viscosity of 3440 cp at 60°F and a reservoir GOR of 75 scf/bbl suggested that the viscosity at reservoir conditions would be reduced to about 1600 cp at 60°F. Assuming a standard oil viscosity mixing rule (logarithm of viscosity weighted by mole fraction) and a ratio of 200 between the light and heavy fraction viscosities, individual values of 180 cp and 36000 cp were obtained at 60°F. For oils of these weights values of 2 cp and 12 cp at 300°F were assumed, and a standard two- constant correlation was used to describe the reduction of viscosity with temperature.

A simple yet effective method for estimating vapor pressures for the two fractions was devised. The vapor pressure for each component was assumed to be in Antoine's form

$$P_{vap} = A \exp[-B/T] \quad (1)$$

where T is absolute temperature, and two points on the Pvap versus T curve determine A and B. For the light fraction these points are its NBP and the temperature where vaporization is first noticed, around 60°F. We found that assuming a vapor pressure of 0.01 psi at this temperature works well. For the heavy fraction, the two points are its NBP and the point Pvap = 0.01 psi at 572°F where the heavy fraction begins to distill. With vapor pressure correlations derived in this way the results of the distillation experiment were matched very closely using the simulator.

The properties of the water, oxygen, and inert gas were standard[4]. Water thermal properties are specified in the simulator. The property data set corresponding to the two-component oil characterization is found in Table 1.

Property data corresponding to a simpler oil characterization were needed to test the hypothesis that the process could be modelled with one oil component. Essentially, the oil component was assumed to be the heavy fraction above, with changes to the following properties. The specific gravity is 0.973 corresponding to 14° API gravity, and a molecular weight of 500 was chosen. The H/C ratio was assumed to be 2.535 as quoted for the dry portion of the tube experiment. The viscosity correlation was reworked to give1600 cp at 60°F and 5 cp at 300°F. The vapor pressure correlation used the NBP of 980°F (from reference 3 using molecular weight and specific gravity) and a "starting" temperature of 60°F where P_{vap} = 0.01 psi. The critical properties, thermal expansion, compressibility, gas heat capacity and vaporization enthalpy were rederived from reference 3 with the new molecular weight, specific gravity and NBP. The desired coke deposition was 1.69 lbm/ft^3 of reservoir, which amounted to 11.59% of the original oil. This fraction was assigned to a separate component which had the same properties as the oil and all of which cracked to coke. The data for the single oil is in Table 1.

Reactions

The reactions link the water and air components chemically to the oil components. The nitrogen was combined with the combustion products so that the inert gas accounted for the combined enthalpy, viscosity and density of the N_2, CO and CO_2. This inert gas component was assigned a molecular weight between that of N_2 and CO_2, and the other properties are of N_2.

The reactions derived for the two-component oil were based on the component formulae in Table 1, which assumed an H/C ratio of 1.6 and an observed CO/CO_2 ratio of 1/4.

The reactions used when the oil was treated as two components are given in Table 2 along with the temperature and concentration dependence of reaction rates. These include heavy fraction burning, light fraction burning, heavy fraction cracking and coke burning. The stoichiometries were derived from balances for the hydrogen, carbon and oxygen separately. For the burning reactions the heat of reaction was assumed to be 20,000 Btu/lbm of fuel (oil or coke). The cracking heat of reaction was 20 Btu/lbm, which can be neglected. The activation energy for the oil burning reactions was 33,300 Btu/lbmole, a standard literature value5. The coke burning activation energy was 23,300 Btu/lbmole. To get the desired coke deposition, 30% of the heavy fraction cracks to coke. This is typical of literature values. Cracking was allowed to proceed at steam temperatures.

For the single-component oil treatment only cracking and coke burning were considered. These reactions were derived in the same way as the above reactions, and are summarized in Table 3. The coke burning rate proportionality constant was adjusted to give 100% oxygen utilization. The cracking rate was set to completely crack the oil in the steam zone of the fire front.

■ Combustion Tube Match

The vertical combustion tube was ignited at the top, and air injection continued for 11 hours. At 9.5 hours water was injected. The tube was simulated using 20 linear grid blocks each 2.5 inches long, small enough to model the structure of the fire front. The variation of air injection rate with time was copied by the injection data entered in the simulator, so that the air injected with time was reproduced. The temperature profiles were used to determine the combustion front location with time. No attempt was made to match the peak temperature levels.

Combustion front positions and oil production histories obtained from simulations using two pseudo-oil components and one component are compared with the experimental results in Figures 1 and 2. The two- component oil treatment did not deposit enough coke and, as a result, predicted an excessive front velocity and early oil breakout (1.9 hours instead of 3.2 hours). As well the simulator's detailed output showed that the amount of oil burned was negligible since heat from the burning coke cracked the heavy fraction and vaporized the light fraction before oxygen could reach the oil. As a result, 100% oxygen utilization at the front caused the fire front velocity to depend principly upon the coke deposited.

On the other hand, the one-component treatment of the heavy crude gave a better control of coke deposition and therefore front velocity, as shown by the better match in Figures 1 and 2. The differences between the front positions for the experiment and one-component case are within errors caused by estimating the front location from the simulators discretized results.

Because of the better control of fuel deposition the one-component oil treatment was used for the sensitivity study.

■ Reservoir Data

The reservoir modelled was not of a specific site but represented a typical Lloydminster heavy oil pay zone. The initial pressure was 500 psi, initial temperature was 75°F and the initial water and oil saturations were 20% and 78%.

In Table 4 are the properties of ten equally thick layers calculated from the analysis of several cores, listed by decreasing permeability. In this study it was assumed that permeability was highest in the middle of the pay zone and decreased toward the upper and lower reservoir boundaries. To model this distribution the vertical dimension was discretized two ways, as three layers and five layers. For the three-layer representation the three layers in Table 4 with the highest permeabilities were lumped into the middle layer. The remaining seven layers were lumped together and then split into identical upper and lower layers. The relative flow capacity and relative storage capacity of each layer were consistent with the original probability distributions. Equal thicknesses were used for the five-layer representation. The middle layer properties were obtained from the two highest permeability layers in Table 4, and the two identical outer layers were derived from the four lowest permeability layers. The other two layers were identical and were derived from the remaining layers in Table 4.

The layer properties for these treatments are shown in Tables 5 and 6. The ratio of permeabilities between the middle and adjacent layers is 4.4 for the three-layer case but only 2.9 for the five-layer case.

Relative permeabilities from a special core analysis are shown in Table 7. The compressibility and thermal expansion of the rock were assumed to be zero. The rock was assigned a heat capacity of 35 Btu/ft^3-F and a thermal conductivity of 24 Btu/ft-day-F.

The well configuration was an inverted repeated nine- spot pattern. Figure 3 shows two adjacent patterns as an example and the element of symmetry that was simulated. The basic reservoir used to optimize the model parameters was one-eighth of a 2.5 acre nine-spot pattern with a 10 ft. pay thickness (Figure 4) with a pore volume of 40838 ft^3. Assuming 30% porosity, the pay zone had 1455 bbl of water and 5673 bbl of oil in place initially.

The producing wells at the edge and corner of the symmetry element each operated with bottom hole pressure equal to the initial reservoir pressure. It was assumed that these wells had been stimulated. The segments of wellbore associated with each layer were coupled together, so that flow between each layer of the formation and the wellbore was rigorously accounted for[1]. Each producer was shut in automatically when oxygen concentration in the wellbore reached 1%, representing breakthrough. Normally breakthrough to the edge well caused it to shut in, and the subsequent breakthrough at the corner well terminated the run.

For the 10 ft. pay cases the air rate for the entire pattern was increased steadily reaching 400 Mscf/d at one year, after which the rate was held constant. The 25 ft. pay air rate was increased to 800 Mscf/d at two years and then held constant. Because the well was fully coupled to the adjacent grid blocks the correct distribution of injection into the formation was done automatically for each layer. Air (21% oxygen and 79% inert gas) at 100°F was injected.

Modifications for Field Scale

The combustion tube report stated that for field conditions the fuel deposition is 1.69 lbm/ft^3 of reservoir and the air requirement is 297.5 scf/ft^3 of reservoir, with a 13.846 coke molecular weight. The reactions were reworked to satisfy these statistics. A coke mass density of 60.8 lbm/ft^3 was used. The H/C ratio changed the oil formula and cracking stoichiometry to

$$C_{36.11}H_{66.66} \rightarrow 36.11\ CH_{1.846}$$

The air consumed per volume and the fuel deposited per volume were used to obtain the coke burning stoichiometry. Assuming 13.846 lbm/lbmole for coke, 21% oxygen in air and 391.97 scf/lbmole at standard conditions, the oxygen consumed is 1.306 lbmole/lbmole coke. The coke burning reaction became

$$CH_{1.846} + 1.306\ O_2 \rightarrow 0.923\ H_2O + CO_{1.689}$$

where the inert gas formula was changed to satisfy the oxygen balance. The fraction of the oil that became coke, based on 30% porosity, 80% initial oil saturation and oil specific gravity of 0.973 was 0.1159 lbm oil burned per lbm OIP.

For the sensitivity study grid block lengths ranged from 16.5 to 100 ft. Even though the simulator cannot model the fire front structure with blocks this size, it does maintain the correct material and energy balances when combustion is taking place. It is these block-size balances that result in pressure changes, viscosity reduction and vaporization which effect areal and vertical sweeps in the field.

For large grid blocks the block temperature corresponds to the average temperature in the block volume and not to the combustion front temperature. This can cause failure of the block to ignite (i.e., the fire front extinguishes), can result in unrealistically high heat losses and can prevent vaporization of residual oil at the front. Usually the reaction rate parameters are adjusted so that coke burning occurs for low block temperatures. Then the heat loss parameters (heat capacity and thermal conductivity of overburden) are lowered until the peak temperature obtained by a burning grid block is near the expected fire front temperature. Finally the oil vapor pressure is modified so that residual oil is vaporized and carried ahead of the front.

For this study the sensitivity of oil recovery to well spacing depends critically upon the extinction of the in- situ fire front due to low air flux rates. The above procedure is not directly applicable for modelling the real extinction of a fire front since in the simulator burning must happen at low temperatures to ignite blocks which should burn. In this study the reaction rate parameters, heat loss parameters and oil vapor pressure were modified, but a special technique was used to account for the front extinction.

The front temperature is the result of a balance of energy created by burning reactions, with temperature variations and loss of heat to the adjacent formations. Excessive heat losses cause the burning temperature to drop below the ignition temperature for coke burning. Simple analytical heat-flow models have estimated the combustion front temperatures resulting from various air flux rates and pay thicknesses[6,7]. From these, minimum air flux rates necessary to sustain combustion, and the assumptions of constant air injection rate and radial outflow, give the distance from the injector at which these minimum flux rates are obtained. This distance is called the extinction radius.

Table 8 contains the extinction radii for three pay thicknesses and two injection rates calculated using 15° API gravity oil, an air requirement of 300 scf/ft^3 of reservoir, an ignition temperature of 500°F, and the minimum air flux rates in reference 7. It is interesting to note that for these cases the extinction radius depends very weakly on pay thickness. This is because for a constant injection rate the additional energy available from the thicker burning zone is compensated by more heat loss from the slower front.

When a reservoir is discretized into blocks for simulation purposes, the grid block size has an effect on this analysis. To reproduce the analytical results, a simple radial outflow geometry was used, and the maximum grid block temperature at the extinction radius was examined. Table 9 shows that the fine grid gave a value reasonably close to the analytical value of 500°F, but the larger blocks resulted in progressively lower temperatures. This is due to excessive heat loss from block areas much larger than the actual area the fire front and overburden have in common. This is an artifact of the discretization of the reservoir.

As mentioned above, the heat loss parameters and oil vapor pressure and viscosity were adjusted to give higher maximum temperatures in burned blocks, so that water and oil vaporization and flow were more realistically modelled. The parameters in the oil vapor pressure correlation were changed to VP1 = 74430 and VP2 = 8227 (see correlations in Table 1); the oil viscosity parameters became LV1 = 4.6.10-6 and LV2 = 9866. The heat loss rock properties were lowered to 5 Btu/ft^3-F and 5 Btu/ft-day-F. The resulting temperatures at the extinction radii are given in Table 9. In the simulations conducted for the sensitivity study these temperatures were identified with the minimum flux rate. For each pattern area (grid block size) and pay thickness the appropriate entry in Table 9 was used in interpreting when and where combustion extinction occurred in the field-size nine-spot pattern.

■ Decoupling Areal and Vertical Effects

Three-dimensional thermal simulations are generally expensive, and since many runs were to be made for the sensitivity study a technique of reducing the computer time and storage requirements was devised. The assumption was that the phenomena which cause incomplete vertical flooding were independent of the causes of partial areal flooding. If so, the 3-D sweep efficiency would be the product of the areal and vertical efficiencies. To test the hypothesis a 10 x 5 x 3 simulation of the reference reservoir (Figure 4) was performed using the areal grid in Figure 5 and the three layer representation in Table 5. In addition a corresponding 10 x 5 areal simulation with one average layer and two 10 x 3 vertical cross-sectional simulations (one for each production well) were conducted. The reservoir volume used for each vertical simulation was based on the burned volume predicted by the single-layer areal result when the front breaks through to the producer, shown in Figure 6. Note that unlike the case for a five-spot pattern, the front has bent toward the corner producer at this point. Figure 7 shows the cylindrical cross-sectional grid used to model the burned volume. Only the injector and one producer appear in vertical runs; the effect of the corner producer was neglected since it produced little oil up to the edge producer's breakthrough. It was assumed that the vertical sweep obtained this way could be applied also to the advance of the front toward the corner producer after the edge producer was shut in.

After the first breakthrough the product of the areal and vertical sweep efficiencies was 27.6% compared to the 3-D result of 26.9%. The difference in breakthrough times of less than 10% was caused by neglecting the corner producer in the cross-sectional simulations. After the second breakthrough the combined sweep was 46.6% compared to the 3-D value of 48.9%. From these results we concluded that the decoupling technique would be sufficiently accurate for the purposes of this study. For the coarsest grid, savings of up to 80% in computer time were realized using the decoupling technique.

In addition to the ultimate oil recoveries, the recovery histories were required so that economic evaluations based on the results of the sensitivity study could be made. A scheme was developed so that a 3-D recovery history could be generated from an areal 2-D recovery history and the ultimate vertical recoveries for the two producing wells. This scheme is consistent with the method of obtaining 3- D recoveries by multiplying areal and vertical sweeps, and preserves the essential behavior of both production well histories. The details are given in Reference 8.

SENSITIVITY RESULTS

■ Areal Grid Type

Choosing a grid system for simulating a process is one of the most critical tasks the engineer encounters. Nowhere is the trade-off between cost and acceptable accuracy so crucial or clear-cut. There are six conservation equations (water, cracking oil, non-cracking oil, inert gas, oxygen, energy) to be solved at each node, and the computer time required to complete a simulation rises very dramatically as the total number of nodes increases. Therefore, it is necessary to use a simulation grid with as few nodes as possible which provides sufficiently accurate results. The main concerns are the effects of numerical dispersion (grid block size) and grid orientation (grid type).

For areal flooding processes in which the primary flow early in the project is radial outflow from an injection well, cylindrical grids such as shown in Figure 5 can be very successful in minimizing grid orientation. A minimum of ten blocks in the radial direction and five in the angular direction were considered. The blocks which fall outside the reservoir were neglected, and those partially inside were assigned the correct volumes and face areas. In this way the reservoir volume and geometry were accurately reproduced.

The 10 x 5 cylindrical grid was compared with the 10 x 5 diagonal and the 9 x 9 parallel rectangular grids in Figure 8. A curvilinear grid for the nine-spot pattern was not considered because a grid based on interwell flow would change when the edge producer was shut in. Figure 9 shows the sensitivity of oil recovery history to changes in grid type. The cylindrical and diagonal grids compare favorably. The parallel grid predicts a much earlier breakthrough at the edge well and significantly less ultimate recovery for the pattern. This behavior is explained by the combustion front positions plotted in Figure 10. The parallel grid predicts incorrect fire front behavior which is dominated by grid orientation and grid size. On the other hand, the cylindrical and diagonal grids agree both qualitatively and quantitatively. We concluded that the parallel grid was not adequate for this application. Since the cylindrical grid has a higher resolution inside the reservoir volume (84% of the blocks compared to the diagonal grid's 60%), it was chosen for use in the remainder of the study. In this application the cylindrical grid has the advantage since the unused region is covered with the largest blocks.

Areal Grid Size

The areal grid in Figure 5 was refined from 10 x 5 to 16 x 8 to examine the effects of areal grid block size on the simulation results. Blocks which fell partially or entirely outside were modified to reproduce accurately the reservoir volume and geometry. Figure 11 shows the small effect that areal grid refinement had on the movement of the combustion front implying that numerical dispersion was not a problem. The times of the first and second breakthroughs differed by about 5% and 7%, respectively, because of the smaller discretization error. For the same reason the 16 x 8 ultimate recovery was 2.7% OOIP less. Therefore, the 10 x 5 cylindrical grid was chosen to perform the sensitivity simulations. The 16 x 8 grid was 2.9 times more expensive to use than the 10 x 5 grid.

Vertical Grid Size

To test the sensitivity of the cross-sectional model (Figures 6 and 7) to grid size, the results of doubling the number of blocks in the radial and vertical directions were examined. The combustion front for the 10 x 3 grid and 20 x 6 grid are plotted in Figure 12 at three times. The layer data in Table 5 was used for both simulations. The front contours show that the effect of vertical override is somewhat pronounced in the finer grid. However, the breakthrough times and oil recovery differ by less than 1%. It was concluded that the 10 x 3 cross-sectional grid was adequate for the study. The finer grid was 8.3 times more expensive to use than the 10 x 3 grid.

Representation of Vertical Variations

Since the variation of permeability and porosity in the vertical direction was significant in this study, it was necessary to ensure that this variation was being modelled accurately. The permeability distribution in Table 4 was represented by three layers (Table 5) and five layers (Table 6). Three was considered the minimum number of layers to model the vertical override and channelling effects that cause incomplete vertical flooding. In these tests the cross- sectional model was used.

Since the middle layers have permeabilities of 626 md and 774 md some difference in vertical sweep was expected. However, the ultimate oil recoveries for the two cases were not systematically different for the pay thicknesses of interest here. The breakthrough time for the five-layer simulations were consistently less than those of the three- layer runs by 3% to 5%. These results indicate that the real permeability variation, and not steam or air override, was dominating the vertical distribution of flow and that the three-layer representation was adequate.

Time Step Size

The time step size in ISCOM is controlled by comparing the magnitude of changes in pressure, temperature, saturations and mole fractions of the last time step with user-specified normal maximum changes. In early parts of the simulation the low oil mobility and changing fire front geometry caused the pressure to increase significantly and then to decrease, so that the time step size was controlled mainly by pressure. Later on, they were controlled largely by the temperature changes as blocks were heated and then cooled. The simulations in this study were run with specified normal changes of 120 psi, 60°F and 20% for saturations and mole fractions.

When the specified normal changes were reduced to 100 psi, 30°F and 10% the ultimate oil recovery, oil recovery histories and breakthrough times were nearly identical with the results of the large normal changes. The only clear difference was that for the areal run 640 time steps were required instead of 320, and the cross-sectional run took 300 time steps instead of 163. These results indicate that the time truncation error in these simulations is very small. Experience has shown that the larger normal changes in variables mentioned above are an optimum compromise between many small time steps and fewer larger time steps which require many Newtonian iterations or fail to converge.

Initial Oil Saturation

The effect of reducing the initial oil saturation to 60% was examined. The principle effect was reduced fuel deposition and less energy generated per burned volume, resulting in a smaller extinction radius. Only a few cases with different pay thicknesses were performed, and these were for pattern sizes where extinction of the front was not significant. For each case the oil recovered was about 12% OOIP less for 60% initial oil saturation. This decreased recovery was due to less energy being available for driving the heavy oil toward the producer via viscosity reduction and vaporization.

Pattern Type

One simulation was performed on one-twelfth of a developed seven-spot pattern. The 10 x 5 cylindrical grid used to model this element of symmetry is shown in Figure 13. The block volumes and areas at the producing end were modified to give the correct reservoir geometry. Because the geometry is different from the nine-spot it is not clear which well spacings can be compared. A meaningful measure that can be applied to all pattern types is the area per producing well. Let L be the uniform well spacing of the repeated pattern. An inverted nine-spot pattern has an area of $4L^2$ with 3 producing wells (4 half wells and 4 quarter wells), and so has an area of 1.33 L^2 per well. An inverted seven-spot pattern has 2 producing wells (6 one-third wells) in an area of 33 $L^2/2$, or 1.30 L^2 per well. Therefore, nine- and seven-spot patterns with the same well spacing can be compared directly.

The recovery histories of the two pattern types were not compared because one has two distinct breakthroughs whereas the other has only one. For a well spacing of 233 ft. ultimate areal recoveries of 65.9% and 68.6% were obtained for the areal sweeps of the nine-spot and seven-spot patterns, respectively. Differences in areal sweep of 2.7% may not be significant, since numerical dispersion and grid orientation can cause differences of this size.

Injection Fluid (Steam)

One steam flood simulation was conducted so that the steam and fire flood processes could be compared on the field scale. The basic oil properties (Table 1, single component oil) and reservoir (Figure 4) were used. Steam of 600°F and 70% quality was injected at constant pressure. Because the mobility of the cold oil was so low the amount of steam injected in the first few years was small. After much of the interwell oil was heated at about three years the injection rate levelled out. Flooding and heating continued until steam breakthrough at the edge producer. After this well was shut in at five years the simulator showed that the redistribution of pressure in the reservoir caused massive steam zone collapse, which took about one year to recover. Injection continued until breakthrough at the corner producer at ten years.

Because the time scale for this process is large and the formation accumulated behind the front is kept at steam temperature, heat loss to the adjacent formations are a major consideration. In this simulation the heat loss parameters were given their unmodified rock values. Fully 67% of the injected heat resided in the overburden and underburden by the end of the project. The predicted ultimate 3-D recovery was 62.5% OOIP, half again larger than the best combustion case, with a project length about three times greater.

Well Spacing and Pay Thickness

In this study it was assumed that the air injection rate is roughly proportioned to pay thickness. For 10 and 25 ft. net pay, 400 and 800 Mscf/d were injected, resulting in extinction radii of 225 and 440 ft., respectively (Table 8). The interaction of these extinction radii with the various well spacings significantly effect the oil recovered.

In reference 7 Dingley uses an analytical model to estimate the effect that fire front extinction has on the volume burned for a 40 acre pattern with the wells in a different configuration, namely the inverted five-spot. Extrapolating his 15° API curve to 800 Mscf/d gives an areal sweep of 47.5% compared to his no-extinction value of 62%. Even though the extinction radius of 440 ft. is only half way toward the producer, higher air fluxes in the interwell direction due to cusping of the front enable the front to reach the producer. Meanwhile air is bled away from other regions inside the extinction radius, and the front goes out. In this study the reaction rate was modified to ignite in large grid blocks, and the simulator was unable to determine if extinction occurred locally, that is, in a single grid block. Instead we used the simulator's results in conjunction with the appropriate extinction radii and reference 7 to estimate how far the combustion front travelled inside the nine-spot pattern.

Figure 14 illustrates the sensitivity of ultimate oil recovery to pattern size and pay thickness in terms of the original oil in place. For the 25 ft. net pay the combustion front experiences breakthrough to both producers in all patterns but the largest. The front in the 40 acre pattern starts cusping toward the edge producer before the extinction radius is reached, and higher air fluxes are present till breakthrough. However, after the edge well was shut in, the temperature and air flux at the front were too low for burning to start. For the 10 ft. net pay only the three smallest patterns had breakthrough to both producing wells. The 20 acre pattern had one breakthrough, and the 40 acre pattern experienced fire front extinction before cusping began, so that no breakthrough occurred.

Figures 14 and 15 show that below about 20 acres for 25 ft. pay and 10 acres for 10 ft. pay the effect of extinction is small, and above these pattern areas the effect dominates the recovery. Figure 15 shows the results on an absolute oil volume basis where it is clear that above these pattern areas there is no significant increase in oil recovered per pattern.

Figures 16 and 17 show the recovery histories derived by the method mentioned earlier in this paper. These histories provide comparative time scales for the field scale combustion process. Basically, the oil recovered is proportioned to air injected. However, after the edge producer is shut in the oil production rate decreases, and increases at a later time. Similar behavior was observed in the three-dimensional simulation but the plateaus were not so flat or long-lived.

The oil production rates in Figure 18 show that there is a distinct difference in behavior between the edge producer and corner producer for a case where breakthrough to each well occurs. As mentioned earlier, the bottom hole pressures of each well were kept constant at the initial reservoir pressure. The edge producer responds to the increasing air injection rate up to one year, and then to the approach of the cusping burning front until breakthrough. The oil rate at the corner producer also rises in the first year and levels out as expected. However, at about 1.5 years its rate decreases because the front cusping toward the edge causes the pressure in the reservoir to drop. The oil rate at the corner does not pick up until the air injected at constant rate has repressurized the burned-out volume enought to move the cold oil in the corner. The plateau in oil recovery history is due to the time required for this repressuring of the reservoir.

CONCLUSIONS

☐ 1. *A complete data set for simulating field scale combustion has been derived. The heavy Lloyd- minster-type oil can be characterized as both one and two pseudo-components. Both representations are able to reproduce an experimental distillation curve.*

☐ 2. *The thermal simulator ISCOM was used to match the fire front velocity and oil recovery history obtained in a combustion tube experiment using the reservoir oil. The two-component oil treatment is unable to lay down the correct amount of coke. The single-component representation successfully reproduces the coke deposition and front velocity. For the dry combustion process in this type of oil (14o API gravity) compositional effects can be neglected.*

☐ 3. *The combustion process can be modelled successfully on the field scale by accounting for the effects of block size on heat loss, oil vaporization and reaction rates.*

☐ 4. *The areal and vertical aspects of the three- dimensional combustion process in this study can be decoupled. The important phenomena (recoveries, combustion extinction) are accounted for. Comparable three-dimensional data can be obtained by combining the predictions of areal and cross- sectional simulations, resulting in considerable savings in computer time.*

☐ 5. *The model parameters (grid type, grid size, time step size, treatment of vertical variations, characterization of oil) were optimized so that the sensitivity study could be performed using efficient, accurate simulations. A 10 x 5 areal grid and a 10 x 3 cross-sectional grid, both cylindrical with the injector at the center, are the most efficient grids not overly sensitive to grid size variations. The time truncation error in the simulations is insignificant. The vertical variation in permeability can be modelled adequately using three layers.*

- *6. Decreasing the initial oil saturation from 80% to 60% causes ultimate recovery to fall from 47% OOIP to 29% OOIP for the basic well spacing.*

- *7. Steam injection recovers up to 50% more oil than the combustion process, over a project life three times as long. In this case 67% of the injected heat flows into the adjacent formations.*

- *8. Assuming a constant air injection rate, increasing the pattern size above a certain point causes a pronounced drop in oil recovery. For the 10 and 25 ft. pay thicknesses, decreasing the nine-spot pattern size below 10 acres and 20 acres does not alter the ultimate recovery significantly from 39% OOIP and 45% OOIP, respectively.*

- *9. Cusping of the combustion front toward the edge producer of the nine-spot pattern causes a drop in pressure and oil rate at the corner producer. The pressure and rate does not reach normal levels again until the edge well is shut in and the burned volume is repressurized by continued air injection.*

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Table 1
Property Data

Component	Water	Heavy Oil Fraction	Light Oil Fraction	Inert Gas	Oxygen	Single Oil Component
Formula	H_2O	$H_{53.09}C_{32.92}$	$H_{17.45}C_{27.86}$	$CO_{1.8}$	O_2	$C_{36.9}H_{57.2}$
Component Properties						
Molecular Weight	18	450	237	40.8	32	500
Critical Pressure (psi)	3206	121	230	730	730	110
Critical Temperature (°F)	705.7	1213	900	-101.7	-181.8	1250
Gas Heat Capacities						
Cp1		46.2	-3.36	7.66	6.713	46.2
Cp2		.211	.2155	$-1.8\cdot10^{-3}$	$-4.88\cdot10^{-7}$	0.237
Cp3		0.	$-6.69\cdot10^{-5}$	$1.98\cdot10^{-6}$	$1.29\cdot10^{-6}$	0.
Cp4		0.	$8.08\cdot10^{-9}$	$-4.78\cdot10^{-10}$	$-4.36\cdot10^{-10}$	0.
Gas Viscosity						
GV1	.00008	.03	.03	.000213	.000220	.03
GV2	1.116	0.	0.	0.702	0.721	0.
Liquid Properties						
NBP (°F)	212	932	572			900
Specific Gravity	1.000	0.980	0.867			0.973
Compressibility (1/psi)	$3\cdot10^{-6}$	$6\cdot10^{-6}$	$6\cdot10^{-6}$			$6\cdot10^{-6}$
Thermal Expansion (1/F)	$1.6\cdot10^{-4}$	$3.8\cdot10^{-4}$	$3.0\cdot10^{-4}$			$3.8\cdot10^{-4}$
Vaporization Enthalpy						
VE1		3976	2534			4306
Viscosity						
LV1		$3.5\cdot10^{-7}$	$1.17\cdot10^{-4}$			$1.87\cdot10^{-5}$
LV2		12186	7610			9500
Vapor Pressure						
VP1		$1.95\cdot10^{10}$	$3.03\cdot10^{6}$			1150
VP2		29200	8024			6060

Gas Heat Capacities (Btu/lbmole-F): $Cp1 + Cp2 \cdot T + Cp3 \cdot T^2 + Cp4 \cdot T^3$

Gas Viscosity (cp): $GV1 \cdot T^{GV2}$

Vaporization Enthalpy (Btu/lbmole): $VE1 \cdot (Tc - T)^{.38}$

Liquid Viscosity (cp): $LV1 \cdot \exp(LV2/T)$

Vapor Pressure (psi): $VP1 \cdot \exp(-VP2/T)$

T - absolute temperature
Tc - component critical temperature

Table 2
Chemical Reactions - Two Oil Components

Cracking

$C_{33.09}H_{52.92} \rightarrow 1.325\ C_{17.63}H_{27.86} + 10\ CH_{1.6}$

$+ 7.2x10^3$ Btu/lbmole

Rate of reaction is proportioned to

$\exp(-E_a/RT)\phi S_o\ \rho_o\ X_1$

where E_a = 33300 Btu/lbmole.

Coke Burning

$CH_{1.6} + 1.3\ O_2 \rightarrow 0.8\ H_2O + CO_{1.6}$

$+ 2.72x10^5$ Btu/lbmole

Rate of reaction is proportioned to

$\exp(-E_a/RT)\rho_c\ p_{oxy}$

where E_a = 23000 Btu/lbmole.

Heavy Fraction Burning

$C_{33.09}H_{52.92} + 43.011\ O_2 \rightarrow 26.46\ H_2O + 33.09\ CO_{1.6}$

$+ 9x10^6$ Btu/lbmole

Rate of reaction is proportioned to

$\exp(-E_a/RT)\phi S_o\ \rho_o\ X_1 p_{oxy}$

where E_a = 33300 Btu/lbmole.

Light Fraction Burning

$C_{17.63}H_{27.86} + 22.667\ O_2 \rightarrow 13.93\ H_2O + 17.63\ CO_{1.6}$

$+ 4.74x10^6$ Btu/lbmole

Rate of reaction is proportioned to

$\exp(-E_a/RT)\phi S_o\ \rho_o\ X_2 p_{oxy}$

where E_a = 33300 Btu/lbmole.

S_o - oil saturation
ρ_o - oil molar density
X_1 - oil mole fraction of heavy fraction
X_2 - oil mole fraction of light fraction
ρ_c - coke molar density
R - gas constant
T - temperature in absolute degrees
p_{oxy} - oxygen partial pressure
ϕ - porosity

Table 3
Chemical Reactions - Single Oil Component

Cracking

$C_{36.4}H_{87.2} \rightarrow 36.6\ CH_{2.535} + 7200$ Btu/lbmole of oil

Reaction rate dependence is the same as in Table 2.

Coke Burning

$CH_{2.535} + 1.536\ O_2 \rightarrow 1.268\ H_2O + CO_{1.6}$

$+ 2.72x10^5$ Btu/lbmole coke

Reaction rate dependence: the same as in Table 2.

Table 4
Rservoir Layer Data

Layer	k(md)	ϕ	$kh/\Sigma kh$	$\phi h/\Sigma\phi h$	Cum $kh/\Sigma kh$	Cum $\phi h/\Sigma\phi h$
1	860	.255	.300	.110	.300	.110
2	688	.301	.240	.102	.540	.212
3	330	.319	.115	.108	.655	.320
4	307	.319	.107	.109	.762	.429
5	252	.325	.088	.110	.850	.538
6	184	.319	.063	.108	.915	.646
7	106	.301	.037	.102	.952	.748
8	60	.267	.028	.090	.980	.838
9	52	.257	.018	.087	.998	.925
10	6	.221	.002	.075	1.000	1.000

h - layer thickness/pay thickness
k - permeability
ϕ - porosity
$kh/\Sigma kh$ - relative flow capacity
$\phi h/\Sigma\phi h$ - relative storage capacity

Table 5
Data for Three Layer Representation

Layer	h	k(md)	ϕ	$kh/\Sigma kh$	$\phi h/\Sigma\phi h$
1	.35	161	.287	.172	.340
2	.3	626	.315	.656	.320
3	.35	161	.287	.172	.340

Symbols are defined in Table 4.

Table 6
Data for Five Layer Representation

Layer	h	k(md)	φ	kh/Σkh	φh/Σφh
1	.2	61	.262	.042	.177
2	.2	269	.321	.188	.217
3	.2	774	.313	.540	.212
4	.2	269	.321	.188	.217
5	.2	61	.262	.042	.177

Symbols are defined in Table 4.

Table 7
Three-Phase Relative Permeabilites

$$S_{ew} = \frac{S_w - .18}{1 - .28 - .18} \qquad S_{eg} = \frac{S_g - .04}{1 - .18 - .32 - .04}$$

$$k_{rw} = 0.295(S_{ew})^{2.5} \qquad k_{rg} = 0.18(S_{eg})^{1.5}$$

$$k_{row} = (1-S_w)^{2.5} \qquad k_{rog} = (1-S_{eg})^{3.0}$$

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) - k_{rw} - k_{rg}$$

S_{ew} - reduced water saturation in water/hydrocarbon system

k_{rw} - water relative permeability in water/hydrocarbon system (and in water/oil/gas system)

k_{row} - oil relative permeability in water/hydrocarbon system

S_{eg} - reduced gas saturation in liquid/gas system

k_{rg} - gas relative permeability in liquid/gas system (and in water/oil/gas system)

k_{rog} - oil relative permeability in liquid/gas system

k_{ro} - oil relative permeability in water/oil/gas system using Stone's Model II (the liquid/gas system is assumed to contain critical water)

Table 8
Combustion Extinction Radii

Pay Thickness (ft)	Minimum Air Flux scf/d-ft²	Front Velocity (ft/d)	Extinction Radii (ft)	
			400 Mscf/d	800 Mscf/d
10	28.3	0.094	225	450
15	18.3	0.061	232	464
25	11.6	0.039	220	439

Table 9
Effect of Radial Block Size on Combustion Front Temperature (°F) at the Extinction Radius

Block Size (ft)	400 Mscf/d		800 Mscf/d	
	Normal† Heat Loss	Adjusted†† Heat Loss	Normal† Heat Loss	Adjusted†† Heat Loss
10	488		541	
33	350	914	461	1158
46.6	318	818	424	1090
66	297	732	388	1005

† Heat Capacity - 30 Btu/ft³-F
Thermal Conductivity - 24 Btu/ft-day-F

†† Heat Capacity - 5 Btu/ft³-F
Thermal Conductivity - 5 Btu/ft-day-F

Figure 1
Location of Combustion Front in Tube Versus Time

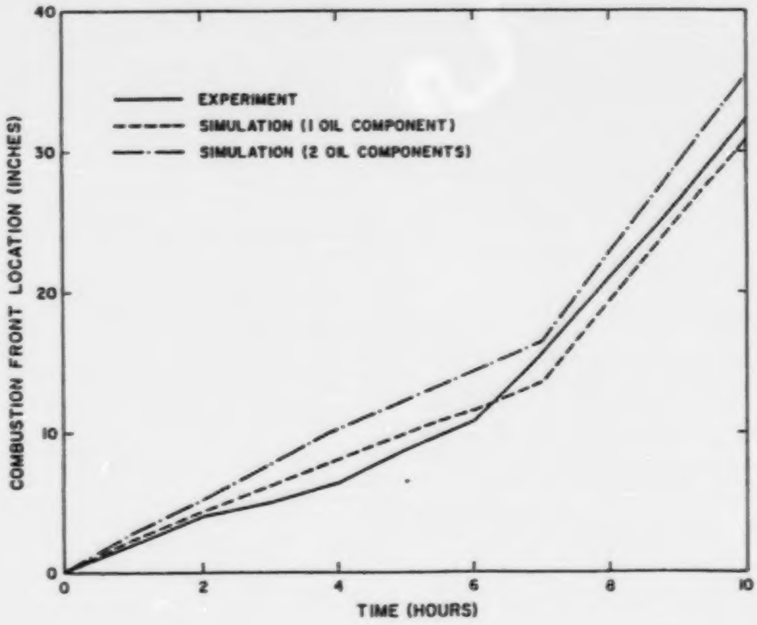


Figure 2
Combustion Tube Oil Production Histories (OOIP is 634 Grams)

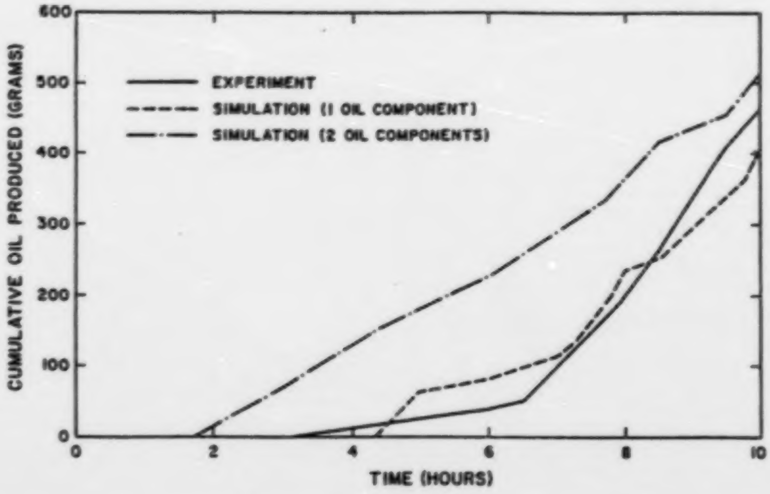


Figure 3
Two 2.5 Acre Inverted Nine-Spot Patterns

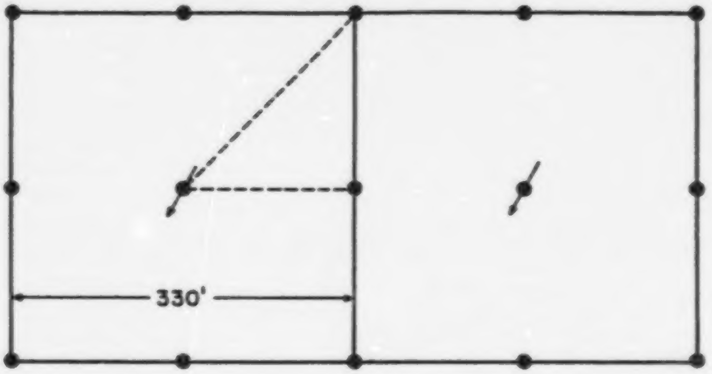


Figure 4
Basic Reservoir - One Eighth of 2.5 Acre Nine-Spot Pattern, 10 Dt. Pay

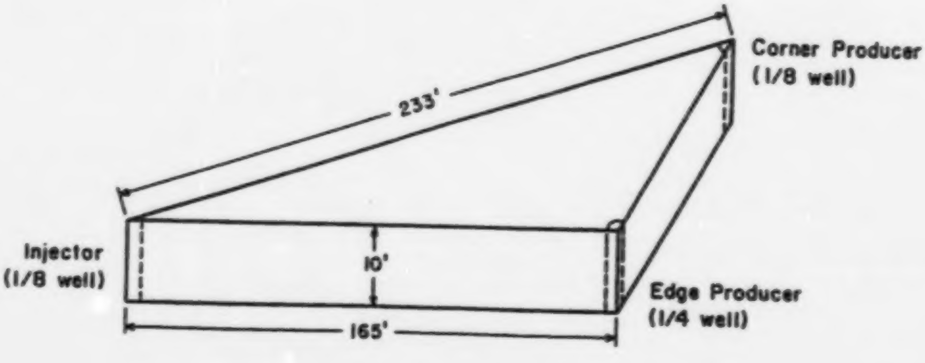

233'
Corner Producer
(1/8 well)
Injector
(1/8 well)
10'
Edge Producer
(1/4 well)
165'

Figure 5
Areal 10x5 Cylindrical Grid

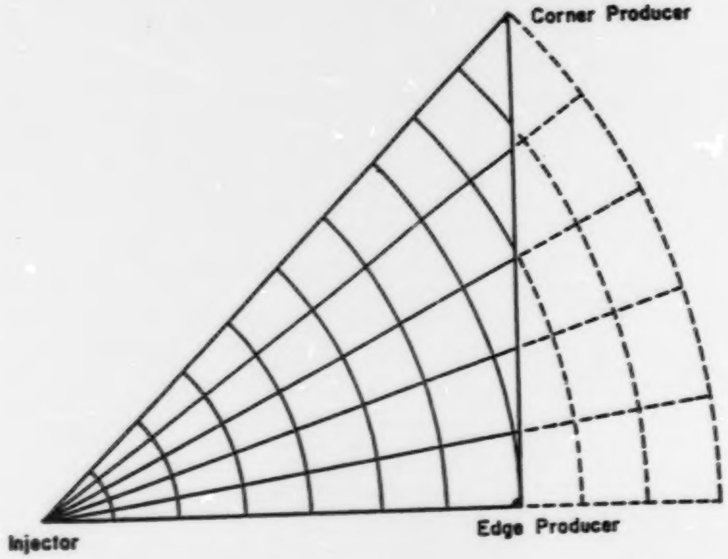

Corner Producer
Injector
Edge Producer

Figure 6
Reservoir Used in Cross-Sectional Simulations

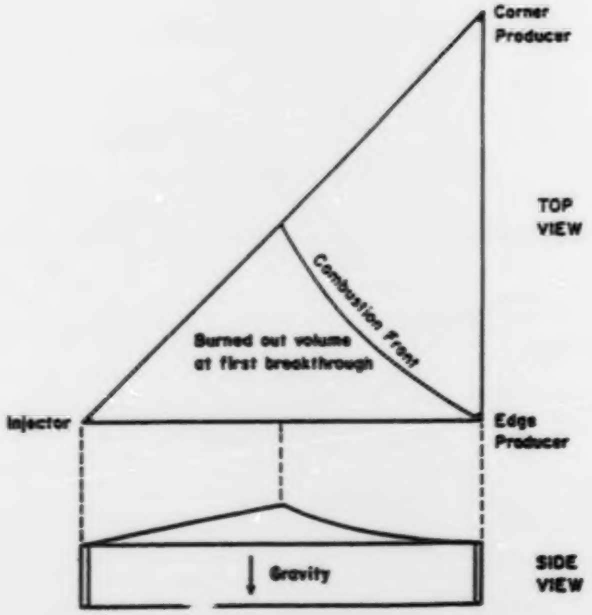

Corner Producer
TOP VIEW
Combustion Front
Burned out volume at first breakthrough
Injector
Edge Producer
Gravity
SIDE VIEW

Figure 7
10x3 Cross-Sectional Grid

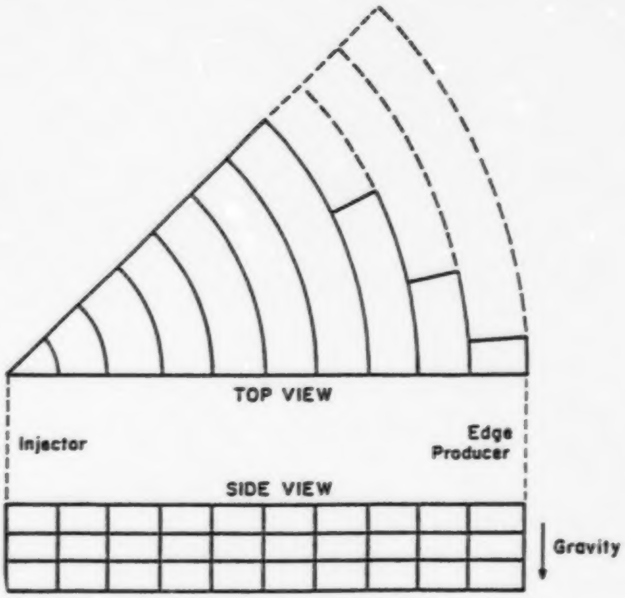

TOP VIEW
Injector
Edge Producer
SIDE VIEW
Gravity

Figure 8
Parallel and Diagonal Rectangular Grids

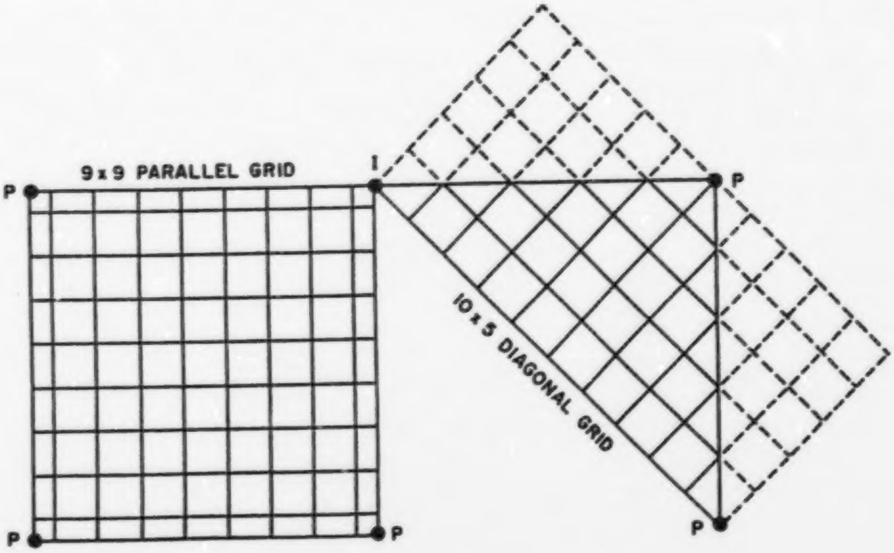

9 x 9 PARALLEL GRID
P
I
P
10 x 5 DIAGONAL GRID
P
P
P

Figure 9
Sensitivity of Oil Recovery to Areal Grid Type (Arrows Denote Breakthrough)

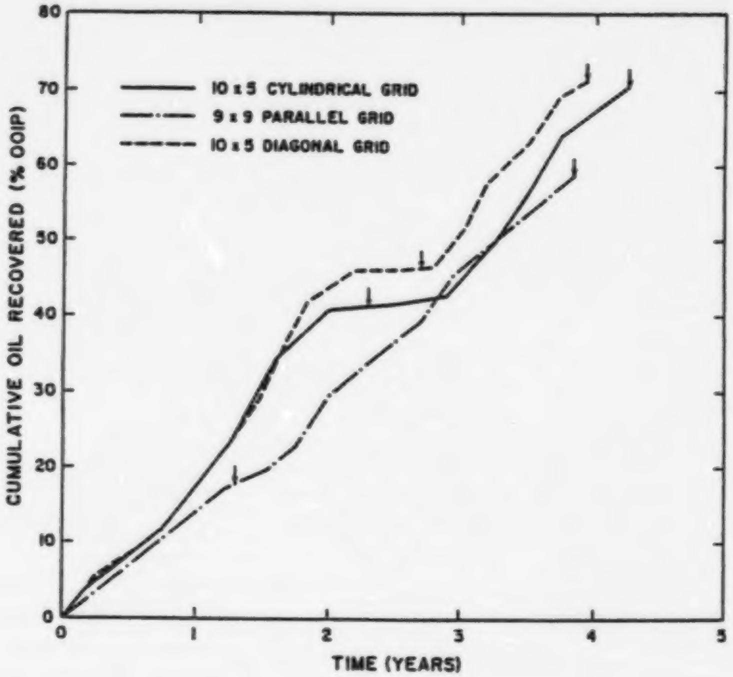


Figure 10
Sensitivity of Areal Sweep to Areal Grid Type

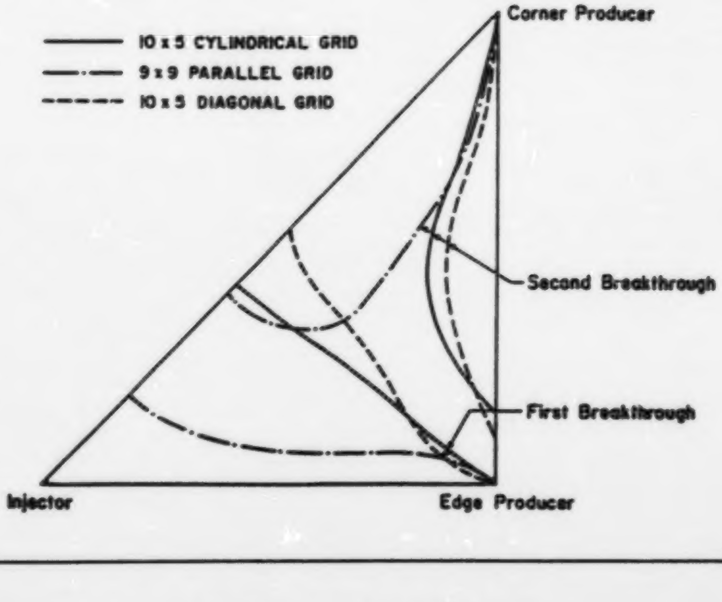

10 x 5 CYLINDRICAL GRID
9 x 9 PARALLEL GRID
10 x 5 DIAGONAL GRID
Corner Producer
Second Breakthrough
First Breakthrough
Injector
Edge Producer

Figure 11
Sensitivity of Areal Sweep to Areal Grid Size

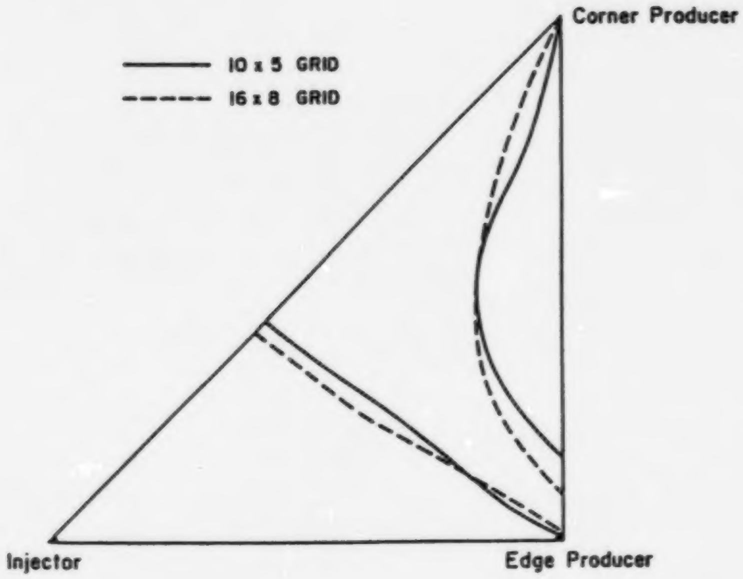

Corner Producer
10 x 5 GRID
16 x 8 GRID
Injector
Edge Producer

Figure 12
Sensitivity of Vertical Sweep to Cross-Sectional Grid Size

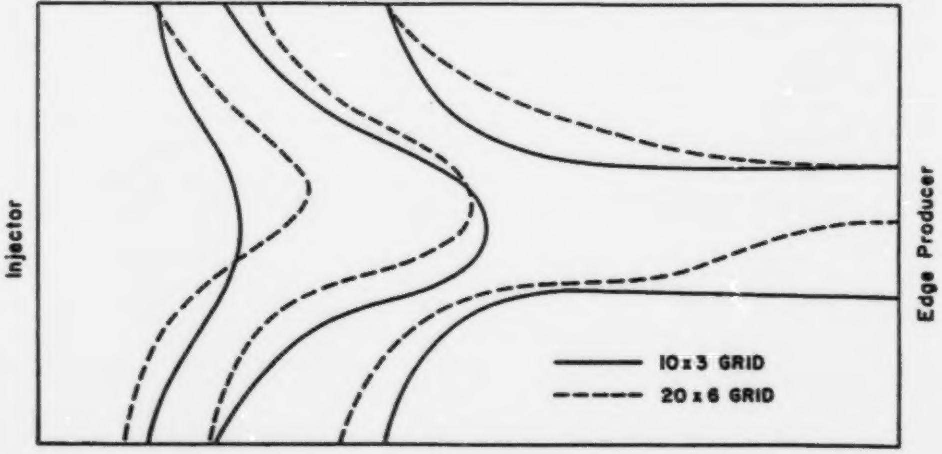

0.5 yr
1.0 yr
1.6 yr
Injector
Edge Producer
10 x 3 GRID
20 x 6 GRID

Figure 13
Grid Used to Model One-Twelfth of Inverted Seven-Spot Pattern

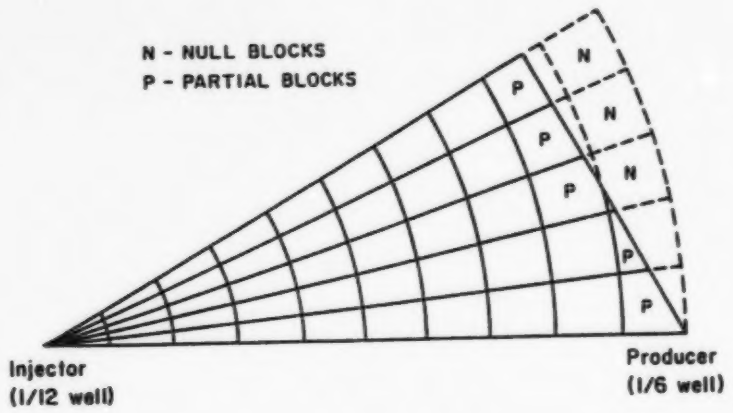

N - NULL BLOCKS
P - PARTIAL BLOCKS
N
N
N
P
P
P
P
P
Injector
(1/12 well)
Producer
(1/6 well)

Figure 14
Sensitivity of Ultimate Oil Recovery (in OOIP) to Pattern Area and Pay Thickness

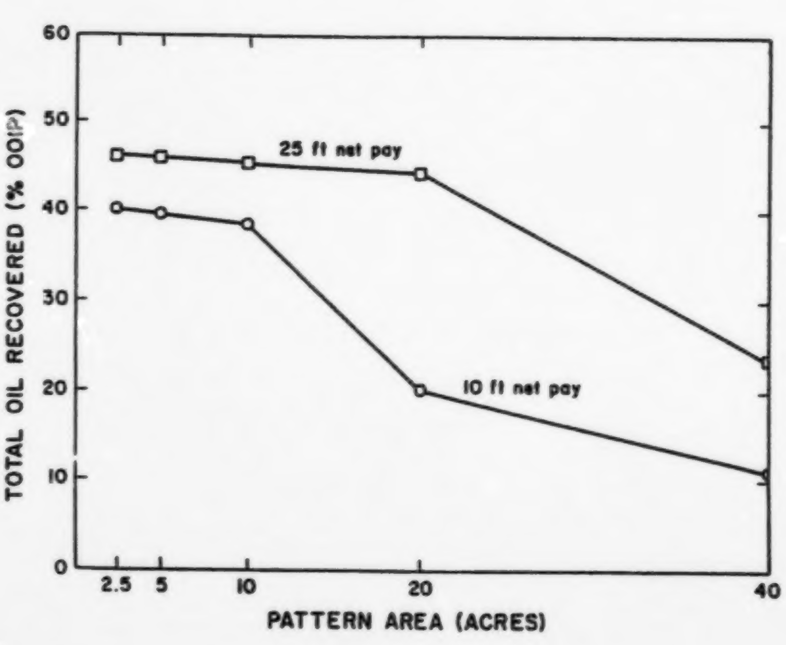


Figure 15
Sensitivity of Ultimate Oil Recovery to Pattern Area and Pay Thickness

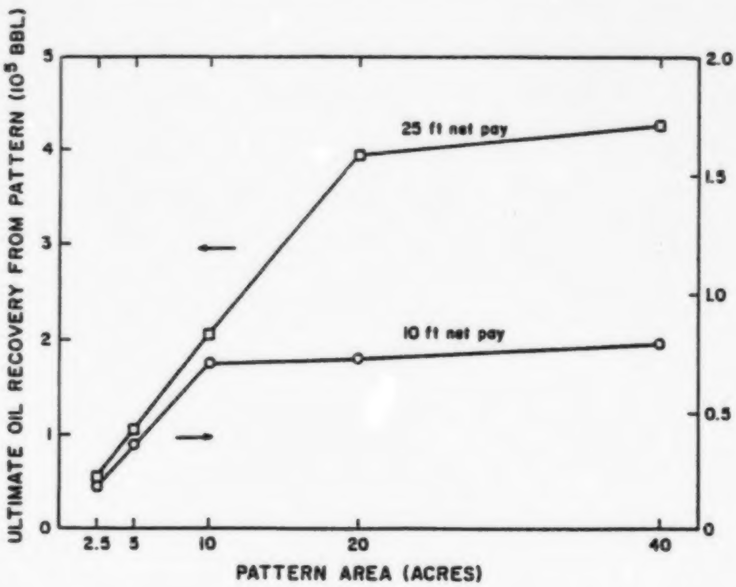


Figure 16
Sensitivity of Oil Recovery History to Pattern Area - 10 Ft. Net Pay

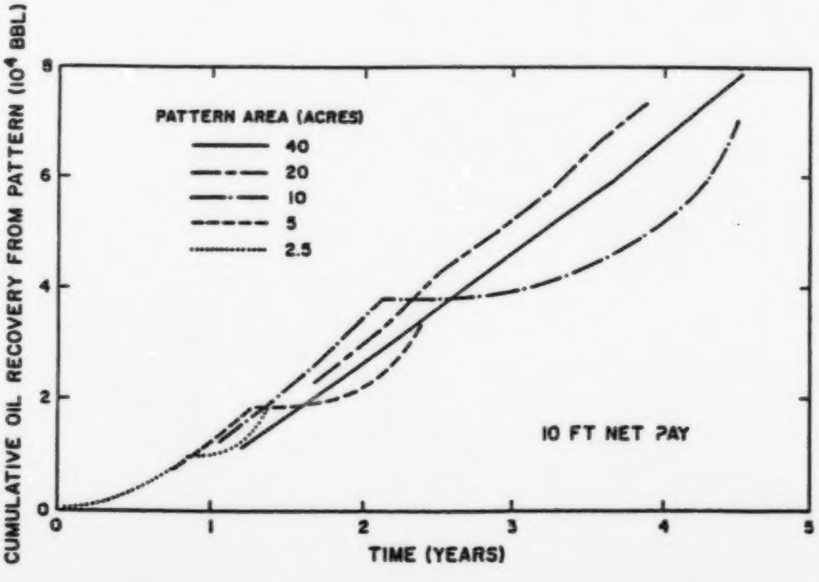


Figure 17
Sensitivity of Oil Recovery History to Pattern Area - 25 Ft. Net Pay

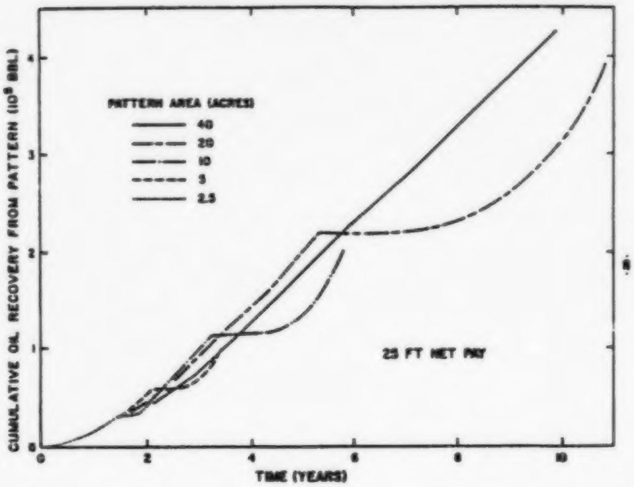
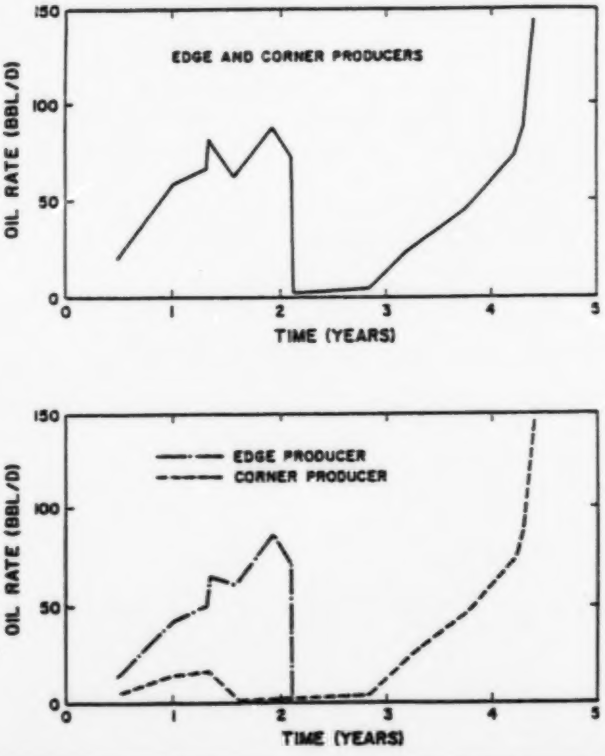


Figure 18
Detailed Oil Rate Histories of the Edge and Corner Wells - 10 Acre Pattern and 10 Ft. Net Pay



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ABERFELDY STEAMFLOOD SCADA SYSTEM

HUSKY OIL OPERATIONS LTD./WILLOWGLEN SYSTEMS LTD

John Galloway
Willowglen Systems Ltd.

Ed Edquist
Husky Oil Operations Ltd.

ABSTRACT

Willowglen Systems Ltd and Husky Oil Operations Ltd. have successfully designed and implemented a Supervisory Control And Data Acquisition (SCADA) system for the first stage of the Aberfeldy Continuous Steamflood Heavy Oil Field. Husky, a fully integrated oil and gas enterprise engaged in all aspects of conventional and enhanced oil recovery, and Willowglen, a world renowned supplier of sophisticated SCADA systems, embarked on the Aberfeldy project with the objective of applying current SCADA technology to monitor, analyze and record injection and production parameters in the field. The SCADA system that was designed and is now currently operational utilizes a distributed processing, multiple layer architecture. At the field level, intelligent remote stations provide electronic monitoring of injection wells, steam generators, producing wells, and well testing facilities. The Field Control Room provides operators with a sophisticated color graphic man/machine interface and data archiving facility for all aspects of the field. Unique features supported at the Control Room level include centralized dynamometer plotting for producing wells on demand and incorporation of manually entered data for facilities not yet upgraded to electronic monitoring. All of the field operating data is also transmitted to a corporate computing center making the data available to reservoir personnel for analysis.

This paper will review the status of the Aberfeldy Steamflood Heavy Oil SCADA system, the design and implementation to date, and the possiblities for future expansion and enhancement of the project.

SITUATION

Aberfeldy Steamflood is an Enhanced Heavy Oil Recovery Pilot Project located in Western Canada close to the provincial border separating Alberta and Saskatchewan. This area of Western Canada is well known for vast reserves of heavy oil and the efforts of many oil and gas companies to optimize production techniques for recovering these reserves. Husky Oil Operations Ltd., a leader in heavy oil technology, embarked on the Aberfeldy Steamflood venture with Texaco Canada to examine more closely the realities of steamflooding in heavy oil reservoirs to increase oil recovery.

The reservoir characteristics of the Aberfeldy Steamflood Pilot are summarized below:

Porosity	30%
Permeability	1,500 Millidarcies
Density	953 kg/cu. meter
Original Oil Saturation (SOR)	75%
Net Pay	10 meters
Sand	Unconsolidated Fine Grained Quartz Sand

The Aberfeldy Steamflood Pilot was conceived as an experimental installation to precede full commercial development of the Aberfeldy field. The Pilot was to be used as a source of data by reservoir and operations personnel so that commercial production might be optimized through maximum production and recovery of original oil in place and through minimum operating costs.

Once production was underway, Husky recognized the need for a Supervisory Control And Data Acquisition (SCADA) system in order to monitor all field data in a timely and organized manner. After a competitive bidding process involving a variety of North American SCADA suppliers, Husky selected Willowglen Systems to supply a sophisticated SCADA system using Willowglen field proven components. As a result of Husky's decision to install a SCADA system, the Aberfeldy Pilot Project became a proving ground, not only for heavy oil production techniques, but also for the SCADA system and associated electronic instrumentation.

PURPOSE AND JUSTIFICATION

A Willowglen SCADA system was installed at the Aberfeldy Steamflood Pilot to achieve two main purposes; to reduce the overall operating costs of the project and to transfer the experience gained to a full scale, commercial development. The justification by which these purposes could be achieved was readily available: the SCADA system would increase on-time of producing wells by consolidating manpower and information in one location; timely and more accurate data collection would be achieved with fewer operators; the paper workload for the operators, associated with manual data collection, would be vastly reduced; and more focused databases could be organized for use by specialized personnel.

The purpose and justification for the SCADA system were directly translated into requirements for Willowglen's design:

- *Automate and simplify the collection of reservoir and operations data.*
- *Integrate automatic and manually collected data into one common database.*
- *Centralize field operations data reporting to assist field personnel in optimizing pilot operations.*
- *Transfer operations and reservoir databases to Husky's engineerng office in Lloydminster for analysis.*
- *Transfer reservoir archives to Husky's head office in Calgary for in depth reservoir analysis.*

IMPLEMENTATION

A Willowglen SCADA system was designed for automatic monitoring of eight production wells, one steam injection well, one temperature and pressure observation well, two test facilities, the produced fluid battery facility and three steam generators.

Aberfeldy Steamflood production wells employ pump jacks with maximum gear box torque of 328 in./lbs. and electric prime movers. Prior to steamflooding, these wells had stroke rates of 1 to 2 strokes per minute. Once the steamflooding was underway, the stoke rate increased to 10 - 17 strokes per minute. The steam injection well, tied directly to generator discharge lines, typically inject steam at 315 °C and 8270 kPa. The observation well has a thermocouple sonde, approximately 15 meters in length, inserted in the formation's producing zone at a depth of 500 meters. Reservoir pressure sensing is achieved with a filled capillary tube running to the surface.

Test facilities at Aberfeldy Steamflood originally consisted of a combination of 7 atmospheric test tanks and pressurized treaters. Each test satellite also contains a manifold and associated valving for each well that allows any well to be put on test and the others to flow into a common "group" line to the battery facility. A casing gas manifold and valving also exists in the test satellite that permits testing of any well's casing gas production.

The Aberfeldy Battery facility consists of a group treater that separates field production into its oil and water components, temporary storage tanks for separated oil and water, and a custody transfer unit for transferring of field production to a pipeline.

Three natural gas fired steam generators were initially used at Aberfeldy, two 50 million BTU units and one 25 million BTU unit. The steam quality of these generators is typically 80%.

In addition to the automatic monitoring at each of these facilities, the SCADA system was also designed to accommodate manual entry from facilities, such as producing wells, that were to remain with manual monitoring.

The specific signals or end points monitored by the SCADA system consist of temperature, pressure and differential pressure transmitters, a thermocouple sonde, BS & W (Basic Sediment and Water) probes, orifice, turbine and positive displacement (PD) meters, and wellhead load cells and position indicators. Appendix 1 itemizes the types of signals automatically monitored at the various facilities.

The SCADA system designed by Willowglen Systems to meet Husky's requirements consists of a three layer architecture located in the field and two additional layers located in Husky's offices (see Figure 1). The field SCADA system consists of Willowglen 200 intelligent Remote Terminal Units, a Willowglen Master Communcations Controller (MCC) and a PDP 11/23 Host computer system (see Figure 2).

Willowglen 200 RTUs are designed around Motorola 6800 microprocessor technology offering the most in field proven reliability and flexibility. Field signals enter the RTU through surge withstand and lightning protection modules that block out signal transients that are so often found in oil field environments. Field signals are then processed and converted to digital format by the appropriate I/O modules such as analog, status and accumulator input modules. Once in digital form, the RTU processor boards manipulate the data, convert it to engineering units, store it in the RTU's database and prepare the information for transfer to the Host computer.

Communication between the Master Communications Controller (MCC) and the RTUs is initiated by the MCC. The MCC operates in a continuous polling mode whereby each RTU is asked to report data sequentially. Willowglen employs a sophisticated Report-By-Exception polling technique whereby the RTUs only respond with data that have changed since the last scan, such as a change in status or a change in analog value. Changes in analog values that result in reported changes is controlled by user defined report-by-exception windows for each analog. This report-by-exception technique and Willowglen's Bose Chaudhuri error checking mechanism ensure optimal RTU response times and data integrity.

The PDP 11/23 Host computer located in the Aberfeldy field office communicates over a 4800 baud link to the adjacent MCC. The MCC responds to the Host's requests for data by preprocessing data received from the field RTUs. The Host computer is able to maintain a dynamic database and historical files with the data received from the MCC. This data is at the operator's fingertips via the operator's color terminals.

Two semi-graphic color terminals and two report/event printers make it easy for an operator to access the field's database. The powerful software used by Willowglen in the Host computer allows an unskilled operator to configure custom reports, calculations and displays, and to supervise and operate all aspects of the field, with minimal system training. Examples of the types of displays available to the operator are summarized below:

- ☐ *Field Overview: shows all wells in the field and their "on/off" status.*
- ☐ *Test Facility display: shows test separators and tanks, metering and associated piping.*
- ☐ *Well Test display: provides the operator with a mechanism for selecting wells for test and for starting and stopping tests.*
- ☐ *Battery display: summarizes the operation of the "group" separator for overall field production and displays the meter values for field oil and water production.*
- ☐ *Steam Generator Summary: displays the piping and a variety of parameters associated with each steam generator.*

Some of these displays were created by Willowglen prior to installation while others were developed by Husky on site.

In addition to these operator support functions and the more common SCADA functions such as data acquisition, database management, report generation, graphical trending and historical data manipulation, the Aberfeldy Steamflood SCADA system also performs a variety of functions that are more specific to the Aberfeldy situation:

1. Steam Generator Efficiency Calculations - these calculations inform the operator as to the operating efficiency of each of the steam generators.

2. Well Test Calculations - well test results for each well are normalized over a 24 hour period and are corrected for residual water content in the oil using BS & W probe.

3. Production Prorationing Calculations - using all the well test results, overall field production volumes and well on-times, the production for each well is deduced on a monthly basis for regulatory reporting purposes.

4. Dynamometer Plotting - from a color terminal in the Aberfeldy field office, an operator can select a producing well and request a dynamometer plot. Within seconds a dynamometer card for that well, plotting polish rod load against position, appears on the screen, the operator can then request a printed copy of the graph and/or a tabular print out of the graph's values.

5. AGA-3 Gas Volume Calculations - the AGA-3 equation for orifice meters is used to measure produced casing gas, solution gas and steam generator fuel gas consumption.

6. Fluid Level Calculations - given manually entered values for joint length and joints to fluid, fluid levels are calculated for each well.

7. Manually Entered Data - a mechanism is provided to support manual data entry allowing full integration of manual and automatic data in the database.

Operations and reservoir data is also transmitted daily from the Aberfeldy Steamflood host computer to a DEC VAX computer in Husky's Lloydminster office using user configurable reports. This transmission is achieved using DECNET over a dedicated, leased telephone line operating at 1200 baud.

Selected reservoir data is retransmitted from Husky's Lloydminster office to a mainframe computer in the Calgary office over a dedicated high speed telephone line as required.

POST INSTALLATION REMARKS

After several years of successful operation, the Aberfeldy Steamflood SCADA system is considered to have fulfilled its original purpose. A larger database of information has been developed about the Aberfeldv facility using more accurate data and with fewer mountains of paper than would have been possible with manual data collection. This data is now being used to formulate a strategy for Aberfeldy's commercial development.

Although operating costs were reduced by having fewer operators collecting data manually, and revenues were increased by maximizing well on-time, one area where additional costs were incurred was maintenance. Trained maintenance staff are required to maintain the electronic instrumentation, and to a lesser extent, the SCADA system. Therefore, the Aberfeldy SCADA system has changed the staffing requirements for the Pilot. Process knowledgeable operators, although fewer in number, now have responsibility for overall field operations rather than just one or two segments of the field. In addition, trained maintenance staff are now required to ensure the instrumentation and SCADA system are operational in order that the operators are supplied with accurate field data.

The reliability and availability of the SCADA system have been excellent, with Mean Time Between Failures (MTBF) in excess of 8000 hours for system components.

An intermittent problem with RTU to Host computer communications was initially encountered in the field. The problem was traced to the RTU communication lines that were located close to buried high voltage transmission lines. This problem, although anticipated, could not be avoided. A simple solution was implemented whereby a communications retry was initiated in the event of a noise burst on the line.

Evaluation of the reliability and usefulness of the various types of instrumentation is ongoing. Of the 80 pressure, differential pressure and temperature transmitters installed, only one failure occurred in the first year and a half of operation.

The most serious instrumentation problem has been with meters for the produced fluid. Finding positive displacement or any other type of meter that can withstand the heavy oil environment as well as producing an electronic signal for the SCADA system has proved to be a difficult problem.

The load cells installed on wellhead polished rods, although reliable, have proved to be inconvenient for these types of wells that require frequent work overs. Husky is currently experimenting with power transducers mounted near the electric motor as a more convenient alternative to the load cells.

FUTURE INSTALLATIONS

The authors, representing both the operational aspects of a heavy oil project and the supplier of the SCADA system, agree on the following guidelines for future heavy oil installations like the Aberfeldy Steamflood facility:

1. Manual data entry should be eliminated where possible. Apart from the direct cost justification for automatic monitoring, the benefit of operators being permitted to focus on field operations instead of manual data gathering would lead to increased opportunities for production optimization.

2. The overall oilfield should be designed with a SCADA system as an integral component rather than adding the SCADA system as an afterthought to an existing field.

3. Portability of instrumentation and RTUs should be carefully considered so that the equipment can be relocated to new wells as old sections of a field become depleted and abandoned.

4. Future installation will benefit from newer Host computer technology and decreased costs. Significant improvements in Host computer memory capacity, disk storage capacity and increased CPU performance will all be available at decreased costs.

In addition to these general guidelines, continuing developments in Supervisory Control And Data Acquisition technology will be available to new heavy oil installations. From Willowglen's perspective, significant improvements in RTU technology are now available. Eight of the processor modules used in a conventional Willowglen intelligent RTU have been replaced with two high density integration modules, but the field proven I/O interface modules remain the same. Willowglen has succeeded in integrating the latest in technology with these field proven I/O modules while maintaining software and hardware compatibility. This advancement has resulted in less expensive RTUs that occupy less space, require less power and withstand greater temperature variations. This newer technology supports an additional layer of distributed processing at the RTU. Distributed processing at the RTU is realized with remotely mounted intelligent I/O racks tied to a common RTU allowing clients to further reduce cabling costs.

Willowglen's software capabilities in the heavy oil area continue to expand and offer enhanced flexibility. Real-time applications continue to develop as more interfaces become available for intelligent and non-intelligent oil field instrumentation. Reservoir simulation software such as steamflood analysis, wellbore heat loss, and injection models, to name a few, are also supported by Willowglen in order to integrate the analysis and operation of field situations.

In conclusion, SCADA systems can be effectively implemented in heavy oil environments. On-going improvements in instrumentation and SCADA technology will continue to assist in the development and operation of heavy oil producing installations.

Figure 1
SCADA System Architecture

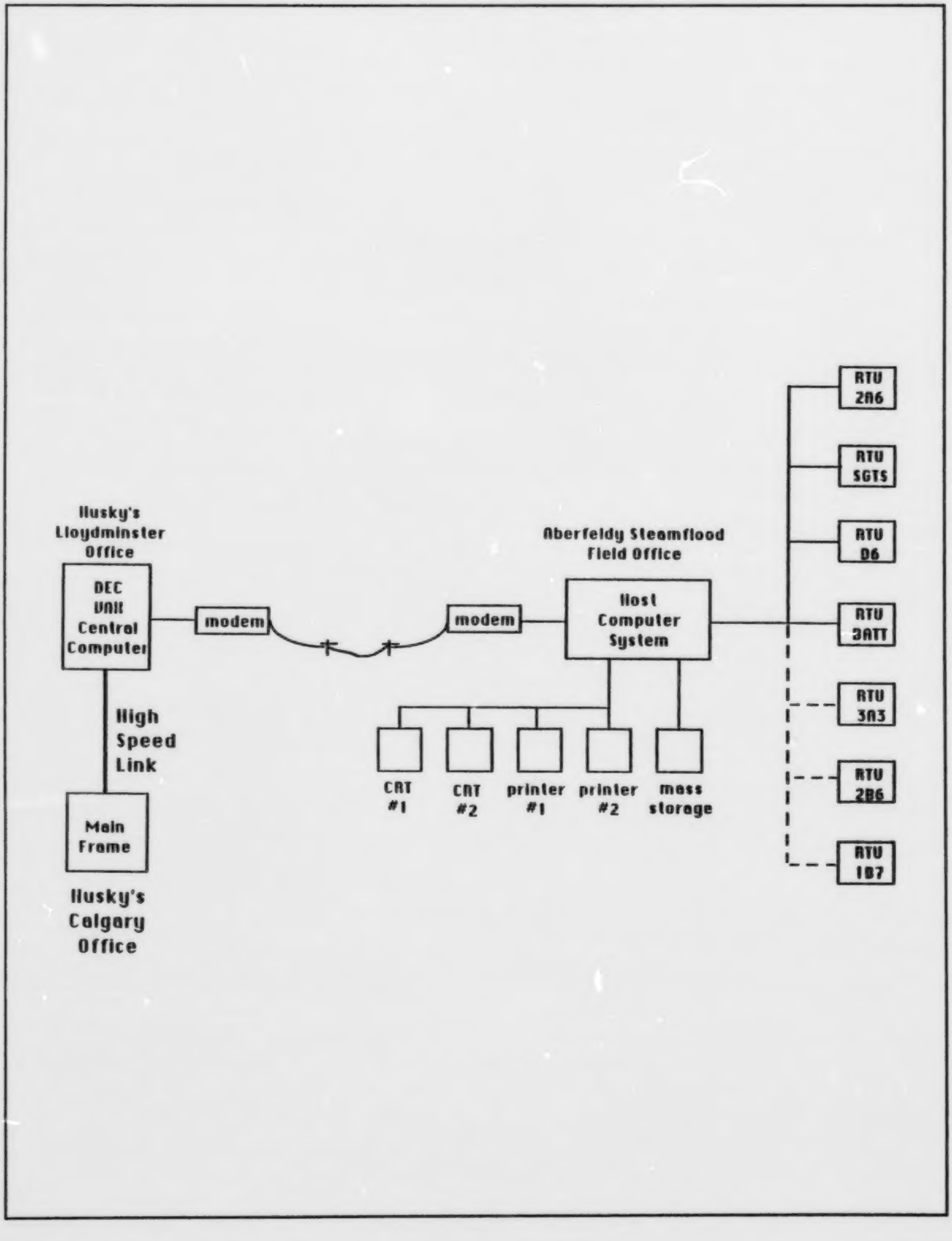
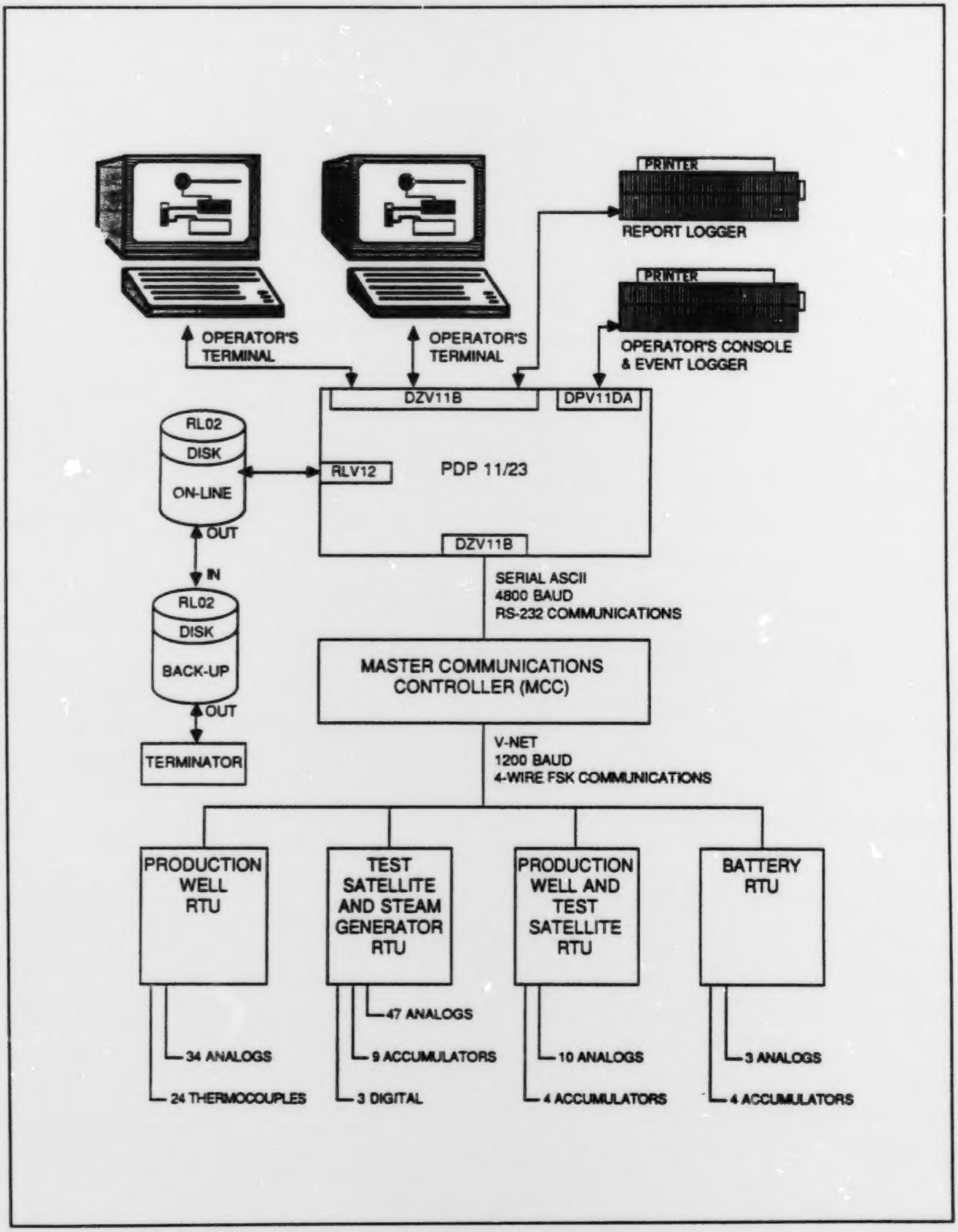

Husky's Lloydminster Office
DEC VAX Central Computer
modem
modem
Aberfeldy Steamflood Field Office
Host Computer System
RTU 2A6
RTU SGTS
RTU D6
RTU 3ATT
RTU 3A3
RTU 2B6
RTU 1B7
High Speed Link
Main Frame
Husky's Calgary Office
CRT #1
CRT #2
printer #1
printer #2
mass storage

Figure 2
Field Scada System


PRINTER
REPORT LOGGER
PRINTER
OPERATOR'S TERMINAL
OPERATOR'S TERMINAL
OPERATOR'S CONSOLE & EVENT LOGGER
DZV11B
DPV11DA
RL02
DISK
ON-LINE
RLV12
PDP 11/23
OUT
DZV11B
IN
SERIAL ASCII
4800 BAUD
RS-232 COMMUNICATIONS
RL02
DISK
BACK-UP
MASTER COMMUNICATIONS CONTROLLER (MCC)
OUT
TERMINATOR
V-NET
1200 BAUD
4-WIRE FSK COMMUNICATIONS
PRODUCTION WELL RTU
TEST SATELLITE AND STEAM GENERATOR RTU
PRODUCTION WELL AND TEST SATELLITE RTU
BATTERY RTU
47 ANALOGS
34 ANALOGS
9 ACCUMULATORS
10 ANALOGS
3 ANALOGS
24 THERMOCOUPLES
3 DIGITAL
4 ACCUMULATORS
4 ACCUMULATORS

APPENDIX I

ABERFELDY STEAMFLOOD SCADA SYSTEM

FIELD SIGNALS AND FACILITIES MONITORED

FACILITY	END POINT	SIGNAL TYPE	COMMENTS
Production Well	Tubing Pressure	analog	Tubing pressure is monitored by the SCADA system to determine each wells upstroke and downstroke pressure. Well operating status is also determined by monitoring tubing pressure.
	Tubing Temperature	analog	
	Casing Pressure	analog	
	Polished Rod Load	analog	A load cell is used to determine the load on the well. When scanned 10 times per second or faster and plotted against wellhead position, a dynamometer plot is obtained.
	Position Indicator	analog	The position indicator is also scanned at least 10 times per second, simultaneously with the load cell to produce a dynamometer plot.
Injection Well	Tubing Pressure	analog	
	Tubing Temperature	analog	
Observation Well	Thermocouple Sonde	thermocouple	Thirty-two type E thermocouples are installed in a sonde in the observation well and are monitored by the SCADA system to produce a bottomhole temperature profile.

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FACILITY	END POINT	SIGNAL TYPE	COMMENTS
Test Facility	Separated Oil	accumulator	When a well is put on test, the SCADA system monitors and records the separated oil and water volumes produced by that well. This data is used to monitor the quality of production of each well and to prorate overall field production back to each well on a monthly basis.
	Separated Water	accumulator	
	BS & W	analog	The separated oil output of the test separator is monitored using a BS & W probe to determine the quantity of water in the oil. This data is then used to correct the water and oil test data automatically.
	Separator Temperature	analog	
	Separator Pressure	analog	
	Casing Gas	analog	When a well is on test, its casing gas volume (in a separate flowline) is measured through an orifice meter.
	Casing Gas Pressure	analog	
	Casing Gas Temp.	analog	
	Casing Gas Liquids	accumulator	The quantity of casing gas liquids scrubbed out of the casing gas is measured through a PD meter.
Produced Fluid Battery	Treater Temperature	analog	
	Treater Pressure	analog	
	Oil meter #1	accumulator	This PD meter measures overall oil production for the Aberfeldy Steamflood Pilot.

FACILITY	END POINT	SIGNAL TYPE	COMMENTS
	Condensate	accumulator	This PD meter monitors the volume of condensate used to blend with the heavy oil produced before injection into the pipeline for transmission to the refinery.
	BS & W	analog	The BS & W reading is used to correct the field's oil production for water content.
	Water	accumulator	This PD meter measures the overall water produced by the Aberfeldy Pilot.
Steam Generator	Feedwater	analog	An orifice meter is used to measure the volume of water entering the steam generator. A vortex meter has also been used, in series with the orifice meter, and monitored by the SCADA system in an effort to test its performance and verify its accuracy.
	Fuel Gas	analog	An orifice meter is used to measure the volume of fuel gas used to fire the generator.
	Fuel Gas Temp.	analog	
	Fuel Gas Pressure	analog	
	Discharge Rate	analog	An orifice meter measures the volume of steam produced.
	Discharge Presure	analog	
	Discharge Temp.	analog	
	Steam Split	analog	Flow nozzles are used to measure steam volumes delivered to each injector.
	Stack Temperature	analog	Stack temperature is used along with feedwater rate, fuel gas rate and discharge rate in a calculation to determine generator efficiency.
	Generator Alarm	digital	When this contact closure occurs, an alarm condition exists at the steam generator.

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ANALYTICAL TECHNOLOGY FOR HEAVY OIL UPGRADING

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ABSTRACT

Key analytical methods used to evaluate performance of heavy oil upgrading processes are reviewed. Microcarbon residue, automated D1160 distillation, existent dry sludge, and metal content methods are introduced with results from actual samples. The microcarbon residue test uses a micro-processor controlled pyrolysis chamber to determine the relative coke-forming tendency of petroleum materials. Yield information is obtained using an automated ASTM D1160 distillation. Measurement of existent dry sludge by hot filtration of samples provides an indicator of potential fouling materials. The extensive use of catalysts in upgrading processes and their poisoning by heavy metals requires the determination of metal content.

The bitumen recovered from the Athabasca oil sands is a very heavy oil requiring substantial upgrading to improve its value. Syncrude Canada Ltd (1) is now installing expanded bed hydrocrackers (Lummus-Crest Fining Process) to complement its Fluid Cokers for the upgrading of bitumen (Figure 1). These units constitute the primary step in bitumen upgrading. The products are fractionated to obtain naphtha and gas oil cuts which are hydrotreated in a secondary upgrading step. This paper describes the state-of-the-art in analytical methods for supporting the primary upgrading processes.

Analytical methods are required to quantify performance. Table 1 lists a number of major bitumen properties and corresponding analytical methods for their measurement. The sulfur and nitrogen contents of Athabasca bitumen are high, e.g., 4.5 and 0.45% respectively. Consequently their removal is an objective of bitumen upgrading. Similarly, density is a figure of merit for petroleum streams. The technologies for determining sulfur, nitrogen, and density are well established and will not be discussed further here. On the other hand technical advances have recently occurred for the determination of carbon residue, distillation, metal content, and existent dry sludge. These advances are the subject of this paper.

MICROCARBON RESIDUE TEST

The amount of carbonaceous residue left after evaporation and pyrolysis of a petroleum sample is an measure of its relative coke-forming tendency. The extent of conversion of the carbon residue during hydrocracking is a measure of process effectiveness. Historically, the Conradson Carbon Residue (CCR) and Ramsbottom Carbon Residue (RCR) as described by ASTM procedures D189 and D524 have been the standard methods for these determinations. A nominal CCR for Athabasca bitumen is 12.6 weight percent, while 10.6 weight percent is a typical RCR. No satisfactory correlation exists for Athabasca bitumen between CCR and RCR determinations. An alternative to the CCR and RCR methods is desirable to overcome operator dependence, reduce operator time, and improve precision. To some degree these objectives are met by reducing procedures to robotic operation. In fact a "turnkey" package can be purchased to perform the RCR test under robot control. The alternative we have taken is to implement the Microcarbon Residue (MCR) test (2) recently issued as ASTM D4530. In the procedure up to twelve samples are placed in a microprocessor-controlled oven. The oven is programmed to a warm starting temperature, e.g., 100 °C, and purged with nitrogen. The program then ramps at 10-15 °C/min. to 500 °C and holds at this temperature for 15 minutes. Power to the oven is shut off and the oven allowed to cool under nitrogen purge. The carbon residue is weighed and reported as a percentage of the sample.

Some of our results from the MCR test are shown in Table 2 and compared with CCR data. For each sample the average result, standard deviation and number of samples analyzed is presented. The essential message from this comparison is that the MCR and CCR methods give the same measure of coking tendency although the MCR has much better precision. In summary the features of the Microcarbon Residue test include:

- ☐ *The results are equivalent to the CCR values.*
- ☐ *Precision is improved about threefold.*
- ☐ *There is no open flame.*
- ☐ *Up to twelve samples can be analyzed simultaneously.*
- ☐ *Only small sample sizes are required.*

There is one feature of Athabasca bitumen that needs to be mentioned in connection with the Microcarbon Residue test. Athabasca bitumen recovered by the hot water extraction process from oil sand is diluted with naphtha and centrifuged to remove water and suspended fine mineral matter. The naphtha is recovered, but the resultant bitumen still contains a small amount of fine mineral matter. This material is characterized by determining the ash content. The ash content may then be used to correct the carbon residue to compensate for suspended solids matter in the sample. A typical ash content is 0.5% by weight.

D1160 DISTILLATION

Distillation may be used to determine the pitch content of feed and products. Pitch is considered as the material with a +524 °C atmospheric equivalent temperature in a distillation. The extent of conversion of pitch to distillable material is a measure of hydrocracker effectiveness. The distillation of bitumen however is nontrivial. The difficulties include:

- ☐ *Cracking of the sample at pot temperatures above 360 °C*
- ☐ *Excessive frothing during degassing.*
- ☐ *Bumping or cracking due to localized overheating arising from poor heat conduction through bitumen.*

We have chosen the Herzog MC-630 instrumentation that automates ASTM D1160. The D1160 is carried out at 1 mm Hg with a separation equivalent of one theoretical plate. The distillation is computer controlled with the operator interface via a light pen and the monitor. Modification of the basic method can be obtained by controlling variables such as the vacuum, degassing sequence, and distillation rate. For bitumen degassing is accomplished by slightly heating the sample and applying vacuum very slowly. In practice this means turning the vacuum pump on for intervals of only a few seconds initially and then progressively increasing the duration of evacuation. Degassing by this procedure is completed in about 15 minutes. Reduction of the distillation rate improves thermal transfer through the sample resulting in more stable distillations and improved repeatability in the atmospheric equivalent temperatures.

Typical precision data for the automated D1160 distilla- tion of bitumen is shown in Table 3. The atmospheric equivalent temperatures for various % off values from the initial boiling point up to the onset of cracking are shown. The final column gives the standard deviation based on the seven replicate distillations performed.

In short the merits of this automated distillation include:

- ☐ *Material to 524 °C atmospheric equivalent temperature is distilled without cracking.*
- ☐ *Less operator time per sample.*
- ☐ *Less operator skill required.*
- ☐ *Improved precision.*

METAL ANALYSES

For hydrocracking the metal analyses of interest are the determination of Ni, V, Co, Mo, and Fe in feed and product streams. Nickel, vanadium, and iron are found in the feed in substantial amounts and will poison the catalyst. Typical levels in Athabasca bitumen are 50-100 mg/L Ni, 150-250 mg/L V, and 300-1000 mg/L Fe. Cobalt and molybdenum in the product is a measure of physical or chemical catalyst decomposition. It should be noted that highly precise results are not a requirement of this application.

The analysis of metals in organic matrices is most easily accomplished using X-ray fluorescence or neutron activation. However, for Syncrude's oil sand plant, water is the most common sample matrix and inductively coupled argon plasma the resident technology. To determine metals in organic matrices two approaches can be used. The older technology is the use of wet or dry ashing as a pretreatment to dissolve the sample in water. Secondly, the sample may be dissolved in an organic solvent and aspirated directly into the plasma. We have focused on this latter approach to reduce sample preparation time and eliminate concern about metal losses during ashing.

The difficulties arising for direct aspiration of bitumen feed into the inductively coupled plasma include:

- ☐ *Viscosity*

  Dilution is required to obtain adequate flow. Samples and standards need the same viscosity to reproducibly aspirate and ensure suitability of calibration.

- ☐ *Power Requirements*

  Significantly more power is required to operate the plasma with an organic matrix than with aqueous matrices.

- ☐ *Presence of -5 µm Solids*

  The bitumen feed to upgrading contains some -5 µm material carried over from the oil sand. Also catalyst fines may be added during hydrocracking. The sample introduction is intended to representatively include these solids in the analysis.

These difficulties are addressed by proper selection of power level, nebulizer/spray chamber, torch, and analytical observation zone. Our operating conditions are shown in Table 4. The Meinhard 'C' nebulizer is intended for high solids content samples. The 1250 watts of power compares with 1150 watts for aqueous samples. The viscosity problem is circumvented by diluting the sample twenty-fold. Standards are also prepared to provide a matching matrix. The dilution has the advantage of lowering working range and ensuring linear calibration.

Example metal results are shown in Table 5. The Ni, V, and Fe concentrations are high compared to the Co and Mo for the feed and consequently have relative standard deviations of 3 to 6%. The relative standard deviation for Co and Mo is much poorer for the low levels present. However for these elements, interest lies in the change in concentration between the feed and the product. The observed increase is presumably picked up from the catalyst. A level of greater than 10 mg/L in Co and Mo is considered significant.

EXISTENT DRY SLUDGE

The final key analytical method is the measurement of existent dry sludge by the hot filtration test. This test is used as an indicator of hydrocracker operability and as a measure of potential downstream fouling. The test measures the existent dry sludge which is operationally defined (3,4) as the material separated from the bulk of an oil by filtration and which is insoluble in heptane. It was originally developed in the early 1950's to measure the cleanliness of residual fuel oils. The application to hydrocracking involves the measurement of the insoluble components in the sample.

Figure 2 is a schematic representation of the equipment used for the hot filtration test. The key to the filtration is a pair of glass fiber filters of 1.6 µm porosity clamped between a filtration vessel and a filtration support. An RTD sensor is mounted in the filtration vessel in very close proximity to the filters. A controller compares the measured temperature with the desired filtration temperature to determine the power to be supplied to a heating unit that slides over the filtration vessel. The heating unit achieves the desired temperature by balancing the heat generated by cartridge heaters and the cooling of an air purge. The sample and filtration vessel are preheated to the desired temperature, and the sample is transferred to the filtration vessel. When the filtration is complete the filters are washed with warm heptane, dried and weighed. The weight increase of the bottom filter is used as an adsorbed oil correction for the top filter. The existent dry sludge is the weight increase of the top filter corrected for oil adsorption expressed as a percentage of the sample.

The quality of the hot filtration data is shown in Table 6. A relative standard deviation of 1.3% on five determinations for a hydrocracker bottoms sample was found. To date we have only limited inter-lab comparisons, but the results are favourable. These results were obtained at 100°C whereas we normally perform the measurements at 150°C. The higher temperature reduces viscosity and improves filterability without producing any visible degradation of the sample. Designing variable temperature capability into our equipment speeds up the analysis time and expands the range of samples amenable to the method.

A previously noted feature of upgrading feedstocks obtained from oil sand is the presence of extraneous material, e.g., clay. This material is included in the existent dry sludge and can contribute to loading problems with the filter. The filtration however uses the large 55 mm diameter glass fiber filter to improve filterability. By dissolving a separate aliquot in toluene and using the same filtration apparatus the extraneous material can be independently determined.

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TABLE 1
ANALYTICAL METHODS FOR PRIMARY UPGRADING OF BITUMEN

Property	Analytical Method
Sulfur	Combustion
Nitrogen	Combustion/Chemiluminescence
Density	Pycnometer
Carbon Residue	Microcarbon Residue
Volume % Distilled	Automated D1160 Distillation
Vanadium	Inductively Coupled Plasma
Nickel	Inductively Coupled Plasma
Existent Dry Sludge	Hot Filtration Test

TABLE 2
COMPARISON OF MCR AND CCR RESULTS

SAMPLE	MICROCARBON RESIDUE Weight %			CONRADSON CARBON RESIDUE Weight %		
	Average	Std. Dev.	n	Average	Std. Dev	n
1	10.39	0.079	22	11.00	0.225	4
2	13.00	0.073	20	13.10	0.414	4
3	14.33	0.115	29	13.93	0.364	4
4	14.32	0.072	30	14.35	0.389	8
5	15.94	0.101	36	15.47	0.230	4

n - number of determinations

TABLE 3
AUTOMATED DISTILLATION OF BITUMEN

Volume % Off	Atmospheric Equivalent Temperature °C	Standard Deviation °C
IBP	248.5	20.5
5	321.6	2.9
10	348.8	3.4
15	373.3	1.9
20	399.3	1.8
25	424.9	1.5
30	449.5	1.3
35	475.0	1.8
40	501.1	1.6
45	526.9	1.2
Cracking	532.3	1.2

* Based on seven replicate analyses

TABLE 4
ICP OPERATING CONDITIONS FOR ORGANIC MATRICES

Power	1250 watts
Reflected Power	<10 watts
Plasma Torch	MAK low flow
Spray Chamber	MAK
Nebulizer	Meinhard 'C' TR-30-C2
Observation Height	15 mm above load coil
Nebulizer Pressure	290 kPa
Pump Tubing	Viton 2.5 mm I.D.
Coolant Gas	250 mL/s Argon
Plasma Gas	33 mL/s Initial Argon 27.5 mL/s Operating Argon
Sample Gas	0.0 mL/s Argon Initial 7.5 mL/s Argon Operating
Sample Uptake Rate	33 μL/s

TABLE 5
METALS IN HYDROCRACKER PILOT FEED AND PRODUCTS

Metal	Stream	Concentration mg/kg	Standard Deviation mg/kg	Relative Standard Deviation %
Nickel	Feed	84.4	3.26	3.86
	Product	65.7	5.80	8.82
Vanadium	Feed	214	7.80	3.65
	Product	120	8.67	7.23
Cobalt	Feed	4.18	0.91	21.7
	Product	6.43	3.15	49.0
Molybdenum	Feed	TR	TR	-
	Product	12.7	8.31	65.4
Iron	Feed	401	22.9	5.70
	Product	670	35.4	5.29

TABLE 6
HOT FILTRATION TEST DATA QUALITY

Precision

1.3% r.s.d. on 5 measurements of hydrocracker bottoms

Inter-lab Comparison

Syncrude wt. %	External Lab wt. %
2.09	1.97 *
3.06	3.05
3.58	3.26

* nearby sample period ** 100 °C

Figure 1
Integration of the Hydrocracker with the Fluid Cokers

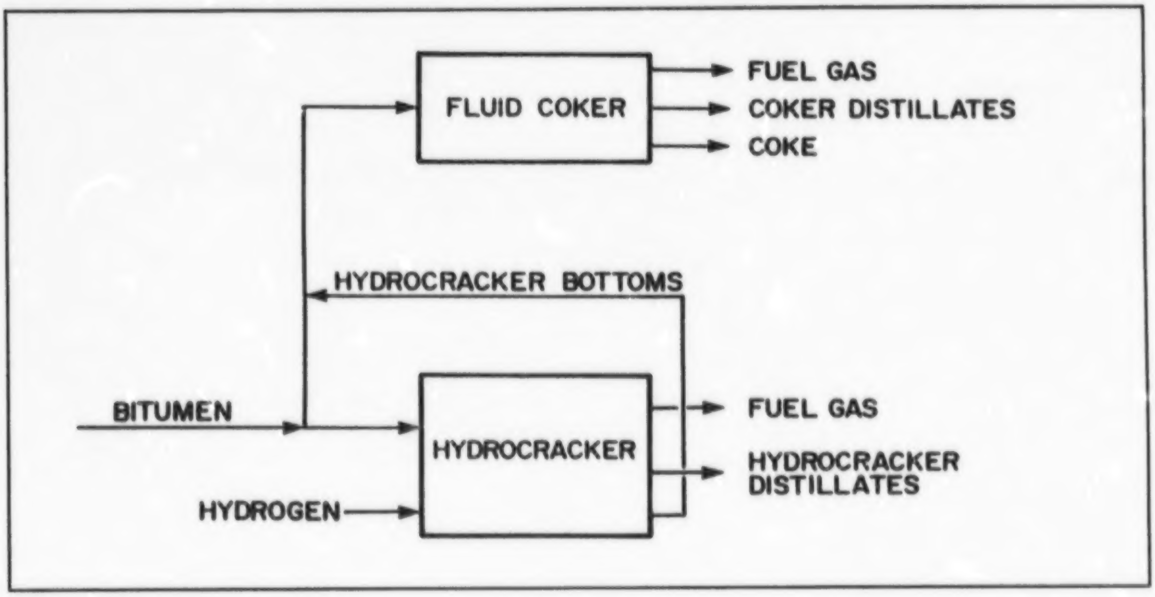
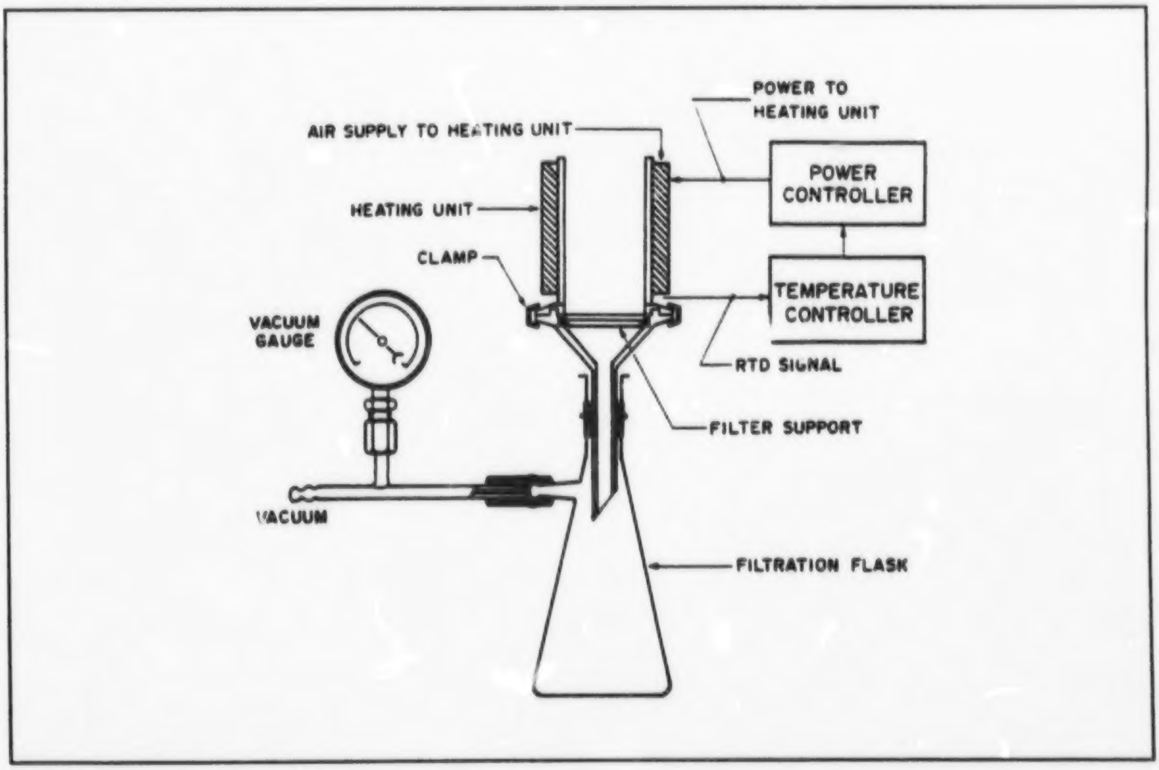

FLUID COKER
FUEL GAS
COKER DISTILLATES
COKE
HYDROCRACKER BOTTOMS
BITUMEN
HYDROCRACKER
HYDROGEN
FUEL GAS
HYDROCRACKER DISTILLATES

Figure 2
Hot Filtration Apparatus


POWER TO HEATING UNIT
AIR SUPPLY TO HEATING UNIT
HEATING UNIT
POWER CONTROLLER
CLAMP
TEMPERATURE CONTROLLER
VACUUM GAUGE
RTD SIGNAL
FILTER SUPPORT
VACUUM
FILTRATION FLASK

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CANMET HYDROCRAKING PROCESS

DEMONSTRATION PLANT OPERATING EXPERIENCE

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ABSTRACT

This report summarizes the operation of the CANMET Hydrocracking Demonstration Unit, in the Petro-Canada Montreal Refinery, from commissioning to the present.

Vacuum tower bottom (VTB) was first fed to the unit in December 1985, and operation continued until March 1986. This was a period of operation without additive, in which the mechanical and process integrity of the unit was proven. First operation with CANMET additive was in May 1986, when a successful test run in the CANMET Hydrocracking mode was carried out. This run showed that operation was predictable and straight forward; that heat effects could be easily controlled; and that pilot plant predictions were reliable. Conversions up to 77 wt.% were documented.

Following the test run, some modifications to the Unit, including the additive preparation facilities were made and a second run was completed in November with very encouraging results.

A third run commenced on March 29, 1987, and the plant continues operation with conversions of 80 wt.% being achieved with IPPL vacuum bottoms feed stock.

Plans are to continue operation, with long term targets to meet commercialization objectives.

INTRODUCTION

The CANMET Hydrocracking Process utilizes an additive to inhibit coke formation while converting high boiling hydrocarbons into light products. The process was initially developed at the Energy Research Laboratories of the Canadian Centre for Minerals and Energy Technology (1) to upgrade oil sands bitumen and heavy oils of Canadian origin.

This hydrocracking technology has subsequently been broadened to include processing the bottom of the barrel from conventional crudes (2, 3).

Petro-Canada acquired the rights to this technology from EMR in 1979, and in 1981 reached an agreement with Lavalin Inc., to jointly develop and commercialize the process. As part of the commercialization program, a decision was made in 1981 to proceed with the design and construction of a demonstration unit. The Petro-Canada Montreal refinery was chosen from a number of possible sites on the basis of refinery experience and synergisms in hydrogen supply and product utilization (7). The nominal unit capacity of 5000 BPSD, although small, was able to use commercial equipment, and fitted refinery operating needs. The unit is viewed primarily as a development tool, but also as a business unit based on conventional economics. The objectives for the project are shown in Table 1.

DESIGN AND CONSTRUCTION

Design and construction of the unit was undertaken by Partec Lavalin, a division of Lavalin Inc., one of Canada's largest engineering and construction firms. The Project team strongly emphasized Canadian content, and achieved 92% through use of Canadian suppliers. For example, the heavy-wall, high pressure reactor vessel (approximately 1.8 m diameter and 21 m height) represents a first of its kind to be manufactured in Canada. Cast ingots produced in Sweden were shipped to Hawker Siddley's plant in Nova Scotia where they were forged into cylinders, machined and then shipped to Versatile Vicker's Montreal shop (5). Each cylinder was fitted as required with previously overlaid nozzles. The cylinders themselves were then overlaid and subjected to intermediate post weld heat treatment. The cylinders were then welded together using the narrow gap welding procedure; the welds overlaid, and post weld heat treatment applied.

Construction of the Demonstration Unit was completed on schedule, and on budget, in July 1985. Figure 2 shows the reactor being lifted into place, Figures 3 and 4 show general views of the units.

PROCESS DESIGN FEATURES

A schematic of the unit is given in Figure 1.

In the process, feedstock is mixed with additive and a small percentage of recycle gas, heated then mixed with main hot recycle gas steam and sent to an upflow reactor. Product is withdrawn overhead and separated into liquid and gaseous streams. A hydrogen rich gas stream is recycled to the reactor with a purge stream being removed to prevent a buildup in methane concentra tion. The liquid stream is fractionated into naphtha, distillate gas oil and pitch. Light ends (C_1 - C_4) are available as fuel gas.

A description of the integration of the unit is given elsewhere (4, 5).

The Demonstration Unit is well instrumented, and has modern computer control, data acquisition and real-time simulation systems (6). This probably represents more sophisticated devices that would be built into subsequent commercial designs, but was provided to facilitate complete data collection on this demonstration facility. There are three special devices to measure fluid density in the reactor, located at different elevations. Sampling capability is extensive, again due to the developmental nature of the unit. There are 52 sampling points for the reaction, separation and fractionation sections, which include a system for removing samples directly from various points of the reactor while operating. The reactor is also monitored using 36 internal and 72 external or "skin" thermocouples. The internal thermocouples are arranged so that radial as well as axial profiles can be obtained, to monitor mixing and hydrodynamic behaviour.

Oil and hydrogen heater designs were optimized to allow a wide range of operating modes. Careful attention was paid to the prevention of coking in the oil heater by good instrumentation, mechanical and hydraulic design.

Although the heater operates with oil exit temperatures in the "coking" range no coking has taken place, nor was there any evidence of the beginning of coke deposition when the heater was inspected.

The separators and the fractionation columns have special design features to allow solids to be handled. There are extensive wash/flushing oil circula tion systems for keeping lines and vessel connections clean when not in use.

The unit was designed to yield products which could be subsequently treated in conventional refinery downstream units.

COMMISSIONING AND OPERATION

The Demonstration Unit was commissioned and tested through the fall of 1985 and winter of 1986 according to the program showed in Table 1. For the reaction, separation, and fractionation sections, this activity was comparable to a normal refinery unit. The unit was pressure tested, warmed up, and put on circulation with hydrogen and start-up oil. A series of hydraulic tests designed to measure gas hold-up and state of mixing in the reactor were undertaken to confirm fluid dynamic correlations used in design.

During this commissioning period, it became evident that some of the concepts employed in the additive section for producing the additive were too complex and a simpler scheme was required. With no additive available, a decision was made to continue commissioning of the high pressure unit, to test equipment under hydrovisbreaking conditions. Vacuum tower bottom was introduced in early December 1985, and the unit operated satisfactorily until April 1, 1986, with all the tests completed.

This proved the mechanical and process integrity of the unit, with products accepted into normal product pools and the pitch product being blended in the heavy fuel oil. The unit was operated as an integral part of the refinery, and a start-up team of scientists and engineers monitored the operation, evaluated equipment, and tested models developed from the data acquired in the pilot plant.

Evaluations of the performance of the reactor, rotating equipment, exchangers, heaters and coolers were carried out during this period. Control philosophy, procedures and fail-safe mechanisms were tested in the three-month period of operation, and found to be effective.

The major challenge in this commissioning period was with the charge pump, which takes VTB at 150°C and 60 psi, and delivers it at system pressure.

This vertical triplex pump required frequent change of cylinder packing. The problem was solved by hardening the pistons and testing new packings until a satisfactory material was found.

The major achievements in this period were in the fundamental technical area, in the understanding of reactor hydrodynamics. Predictions of reactor mixing and gas hold-up, based on cold model work, were confirmed, and the hydrodynamic behaviour of the reactor over a wide range of liquid and gas rates was determined.

During the period of operation at low conversion the design concept for additive preparation was reviewed and tested at Petro-Canada's R&D laboratories. An initial charge of additive was then prepared at an equipment manufacturer's facilities for a test run at the Demonstration Unit.

The objectives of the test run were to evaluate the CANMET Hydrocracking Process, and to obtain data for an economic evaluation. In the course of the test run, mathematical models for conversion, yield, heat effects (temperature profile, quenching system, etc.) and hydraulics were evaluated and updated; and equipment was evaluated while under exposure to three phases for the first time. The test is rated as a milestone in the successful development of the CANMET Hydrocracking Process.

The 565°C+ VTB feedstock was nominally a Western Canadian blend, with properties as listed in Table 2. Based on pilot plant work this is considered to be one of the most difficult feedstocks to process. The test plan was for three feedrates at 60% conversion, and one at 70% conversion. Achievements were with 3000, 4000 and 4800 barrels/day at approximately 65% conversion, and 3000 barrels/day at 77% conversion of 524°C+ material. Higher conversion runs were prevented only by run-out of the available additive. During this run, a trial burn of cutback pitch in the boilers gave satisfactory results.

Surveys were taken to provide data for material balances, and for the economic model. Some of these data are given in Tables 3 and 4. Future reports will elaborate on this data. Correlations with pilot plant data for pitch conversion and product yields were good, as shown in Figure 5 giving confidence in models based on pilot plant data.

Readings from density meters, internal temperatures, and reactor sampling confirmed predictions for gas hold-up and extent of mixing in the CANMET reactor. Heat of reaction was within the range of prediction from pilot plant numbers, and reactor temperatures were easily controlled.

One of the most significant features of the operation was the thermal stability of the reactor. Despite several deliberate and non-deliberate upsets to the reactor, no serious temperature deviations occurred and in each case the unit was back in a steady state of operation within a few hours. In this regard the process is extremely forgiving. The temperature controls provided for the reactor/charge heaters work extremely well in maintaining steady temperatures.

The additive delivery system, product separation, letdown, and fractiona tion worked well in the three-week run. The charge pump continued to be a challenge, with pump packing problems. A complete inspection of the unit was undertaken following the test run. There was no evidence of the beginnings of corrosion or erosion, indicating that there were no severe problems with materials chosen.

Following the test run, the additive preparation section was modified and commissioned, and the Demonstration Unit restarted in November 1986. Improved operation was obtained with integrated additive facilities and charge pump service was satisfactory. Following an operation of over one month, a mechanical failure in the additive injection system forced a shutdown. These problems were resolved and the unit prepared for recommissioning by the end of December; however, the start-up was further delayed because of scheduled turnarounds of the hydrogen generating units and difficulties with other refinery units. Operation of the CANMET unit resumed at the end of March 1987. Conversion levels were initially held at 65 wt.% to establish base line data then progressively increased in 5 wt.% increments. The unit is currently operating at 80 wt.% conversion with no indication of coke formation.

FUTURE PLANS

The Demonstration Unit will be operated continuously to prove high service factor, demonstrate high conversion and generate cash flow. During this period it is intended to evaluate the optimum additive formulation and addition rates for different conversion levels.

Tests are planned, for 1988, with a Western Canadian heavy oil, and with a segregated import oil. Plans are in hand to modify refinery tankage to accommodate such runs.

The anticipated yields from Cold Lake and Lt. Arabian Vacuum Bottoms are given in Tables 5 and 6.

CONCLUSIONS

Commercially available equipment has been shown to work satisfactorily under CANMET Hydrocracking Process conditions. Early indications are that there are no problems with materials of construction, as there has been no sign of corrosion or erosion to date.

Demonstration unit operation in the CANMET Hydrocracking mode proved to be predictable and straightforward. A high degree of "forgivingness" was in evidence, where upsets due to external factors resulted in a smooth reaction response with ample time for process adjustment.

Correlation with pilot plant predictions was found to be excellent, giving confidence in the scale-up. Pitch conversion, obtained from pilot plant data and predicted using a sophisticated computer model, was within a few percent. Innovations such as density meters and reactor sampling have proved their worth, yielding insight into reactor hydrodynamics to improve the operation.

The reaction, separation and fractionation sections had high service factor (0.98 over 3 months) on first time operation. Initial concepts for making additive were too complex, and delays were incurred in commissioning, and in developing a new, simpler system. Simplified additive was purchased and tested in 1986, then modifications were made to produce additive in the refinery. Demonstration Unit operation with this simplified additive has been very encouraging.

Disposition of CANMET products into conventional refinery streams posed no operating difficulties nor was product quality affected. A trial burn of cutback pitch in the boilers gave satisfactory results, with the majority of the pitch blended into the heavy fuel oil.

Future plans include long term steady operation at most economic conversion conditions, with continuing technology development and further optimization. Operation will provide a positive cash flow for the refinery, even under today's conditions of reduced crude oil prices and relatively low light/heavy oil differentials.

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Table 1

CANMET HYDROCRACKING DEMONSTRATION UNIT
COMMISSIONING AND START-UP

Objectives

Demonstrate commercial viability of the process.
- High conversion operation
- Use of commercially available equipment
- Correlations with pilot plant predictions

Economic Incentives for the Refinery
- High service factor operation

Start-up Program

Mechanical checks

Confirm fluid dynamic correlations

Mechanical and process integrity

Demonstrate operability of the CANMET Hydrocracking Process

Confirm mathematical models

Establish correlation with pilot plant

Table 2

FEEDSTOCK PROPERTIES
INTERPROVINCIAL PIPELINE (IPL)

Type: IPL vacuum bottoms. Nominally 565°C+ feedstock	
Gravity 15/15 °C. °API	1.02
Pentane Insoluble, wt. %	17.5
Toluene Insoluble, wt. %	0.6
Asphaltene, wt. %	16.9
CCR,* wt. %	18.9
Ash, wt. %	0.06
Nitrogen, wt. %	0.64
Sulphur, wt. %	2.91

*CCR = CONRADSON CARBON RESIDUE

Table 3

PRODUCT YIELDS, BASED ON FEED
BASED ON DEMO UNIT PERFORMANCE

Conversion Products	Wt.%	64	77
C_1 - C_2	Wt.%	5.5	6.8
C_3	Wt.%	0.5	0.8
C_4	Wt.%	0.6	0.8
Naphtha (C_5 - 175°C)	Vol.%	13.5	19.5
LGO (175 - 315°C)	Vol.%	27.7	35.3
HGO (315 - 524°C)	Vol.%	28.3	29.8
Pitch (524°C+)	Vol.%	32.7	21.0

Table 4

PRODUCT QUALITIES
BASED ON DEMO UNIT PERFORMANCE

	NAPHTHA C_5-175°C		DISTILLATE 175-315°C		GASOIL 315-524°C		PITCH 524°C+	
	64%	77%	64%	77%	64%	77%	64%	77%
Gravity °API	63	62	36	34	21	18	-5	-13
Sulphur Wt.%	0.38	0.27	1.04	0.99	1.63	1.46	2.86	3.31
Nitrogen Wt.%	0.2	0.2	0.2	0.28	0.57	0.58	1.05	1.29
TI* Wt.%	-	-	-	-	0.0	0.0	7.7	20.0
CCR Wt.%	-	-	-	-	0.3	0.4	39.2	51.2

*TI = Toluene Insolubles

TABLE 5
COLD LAKE FEEDSTOCK (404°C+) AND PRODUCT INSPECTIONS (90% CONVERSION)

Feedstock		
Gravity	API	6.4
C/H Ratio		8.06
CCR	Wt.%	18.20
Metals	PPMW	357
Pitch	Wt.%	73.0
Sulphur	Wt.%	5.16
Nitrogen	Wt.%	0.57
Products		
C_1 - C_3	Wt.%	5.4
C_4 - 204°C	Vol.%	29.3
204 - 343°C	Vol.%	42.9
343 - 524°	CVol.%	28.0
524°C+	Vol.%	6.6
Distillate		
C_4 - 524°C	°API	29.9
	S Wt.%	1.76
	N Wt.%	0..32

TABLE 6
LT ARABIAN VACUUM BOTTOMS (552°C+) FEEDSTOCK AND PRODUCT INSPECTION (85% CONVERSION)

Feedstock		
Gravity	oAPI	7.36
C/H Ratio		8.35
CCR	Wt.%	22.3
Metals	PPMW	155
Pitch	Wt.%	98.28
Sulphur	Wt.%	4.34
Nitrogen	Wt.%	0.26
Products		
C_1 - C_3	Wt.%	6.2
C_4 - 204°C	Wt.%	18.2
204 - 343°C	Wt.%	27.6
343 - 524°C	Wt.%	32.4
524°C+	Wt.%	14.8
Distillate		
C^4 - 524°	°API	30.24
	S Wt.%	1.80
	N Wt.%	0.19

Figure 1
Canmet Hydrotreating Process

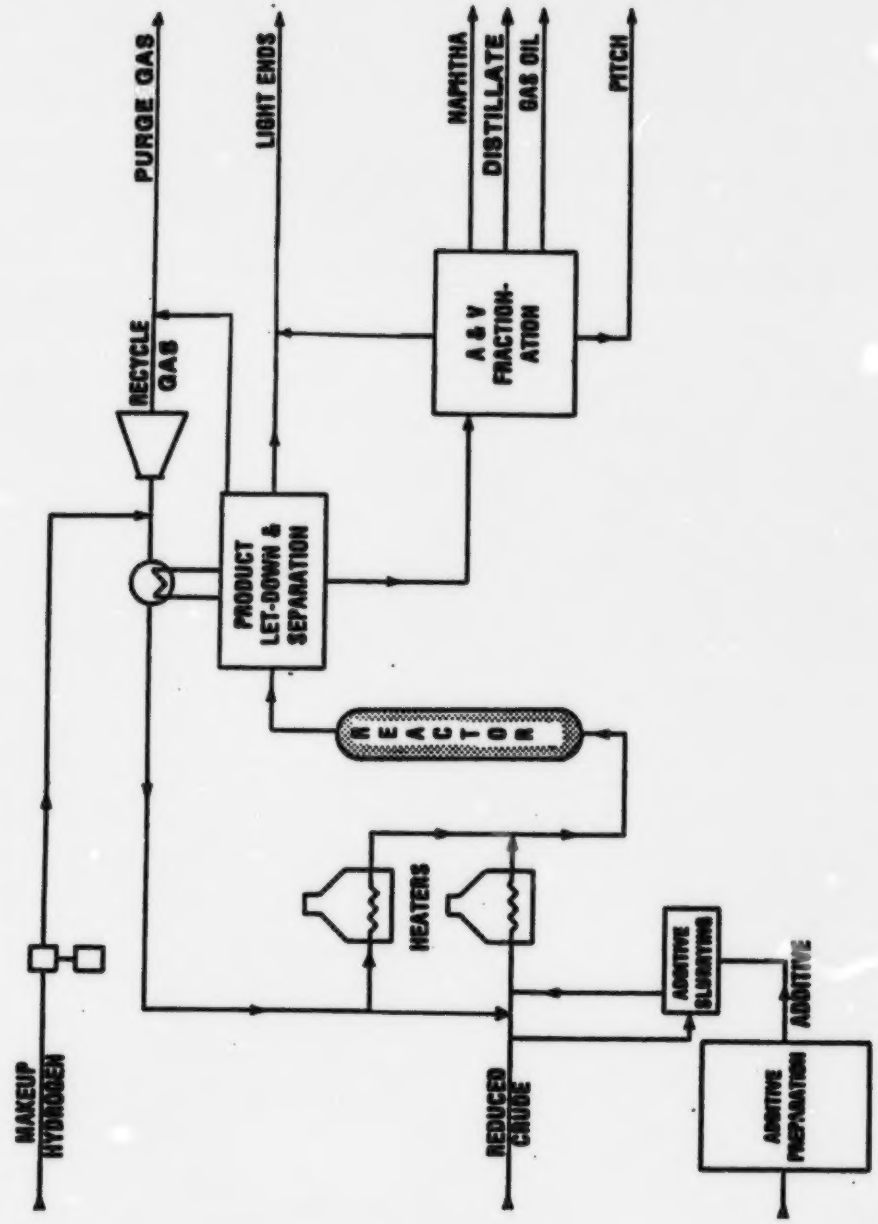

PURGE GAS
LIGHT ENDS
NAPHTHA
DISTILLATE
GAS OIL
PITCH
RECYCLE GAS
A & V FRACTION-ATION
PRODUCT LET-DOWN & SEPARATION
REACTOR
HEATERS
MAKEUP HYDROGEN
REDUCED CRUDE
ADDITIVE SLURRYING
ADDITIVE
ADDITIVE PREPARATION

Figure 2
Reactor Erection

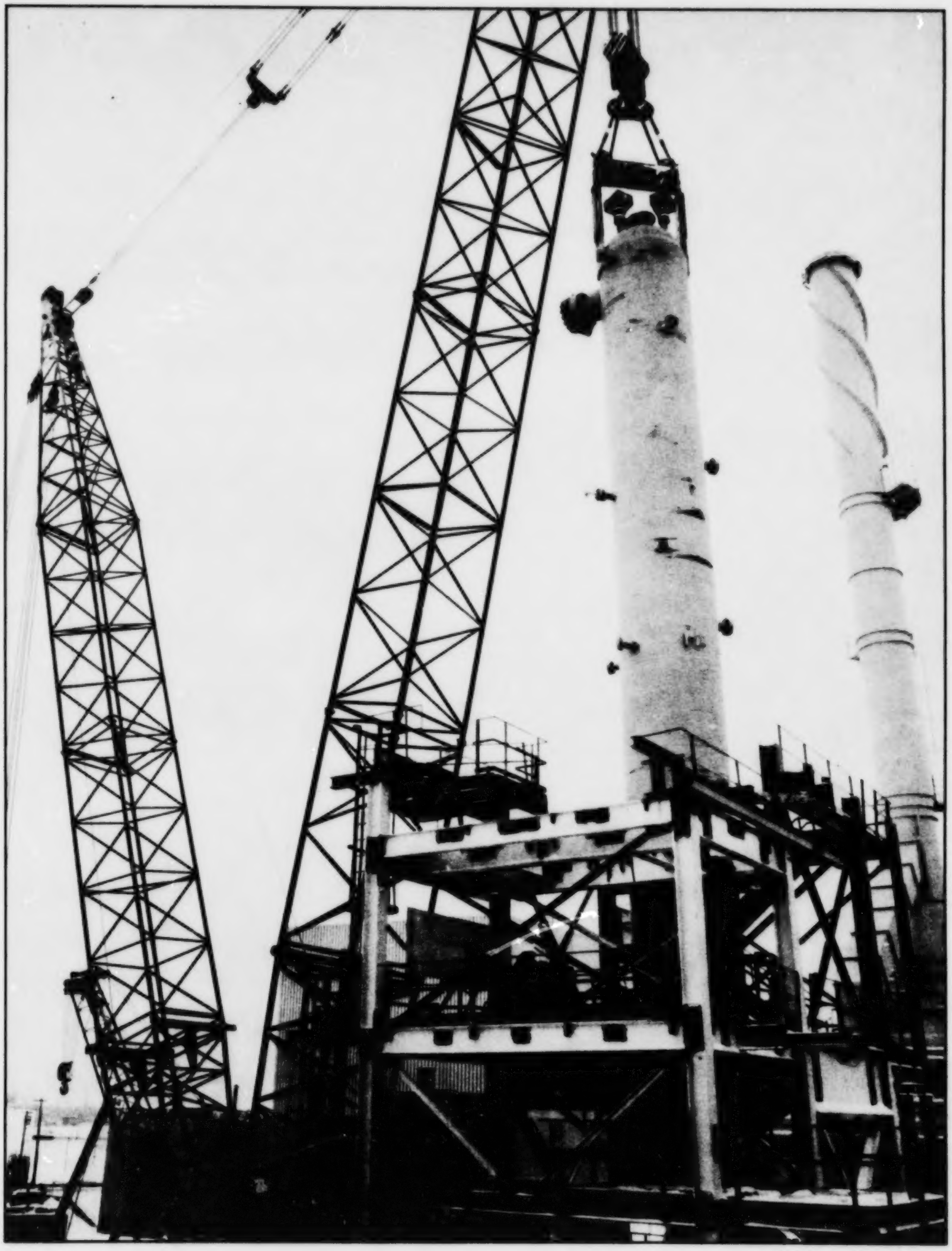


Figure 3
Aerial View of Unit

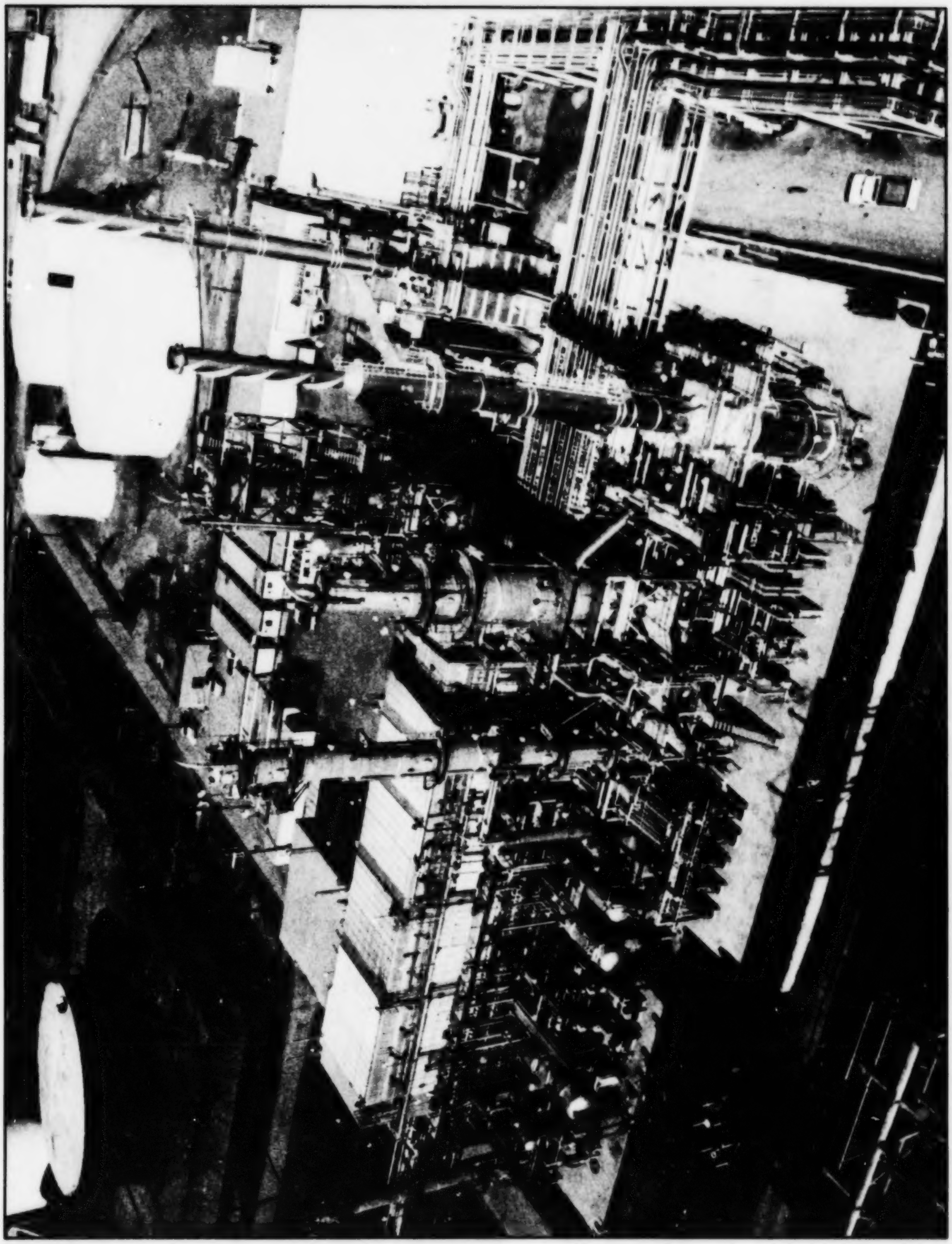


Figure 4
Reactor Structure

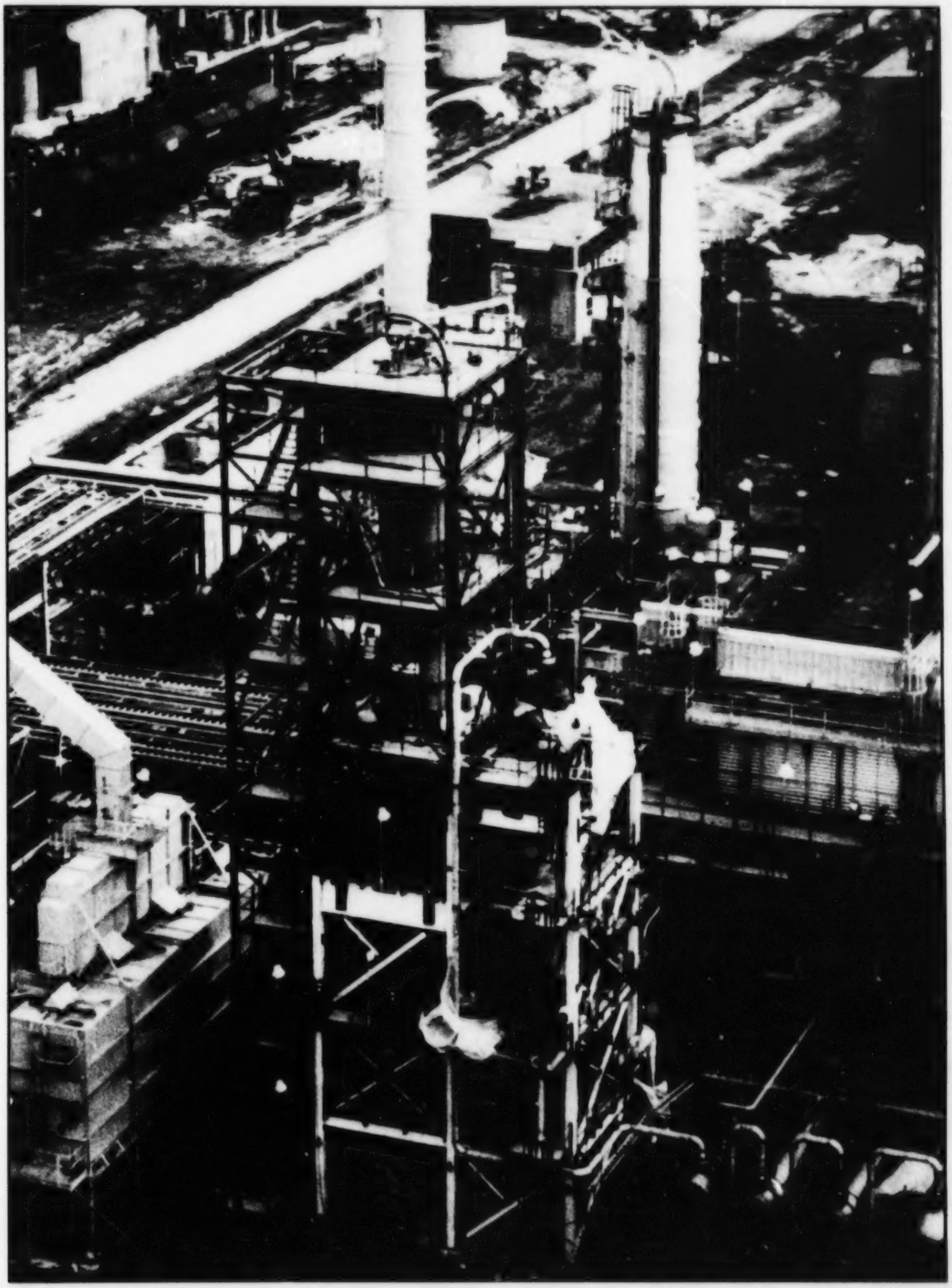
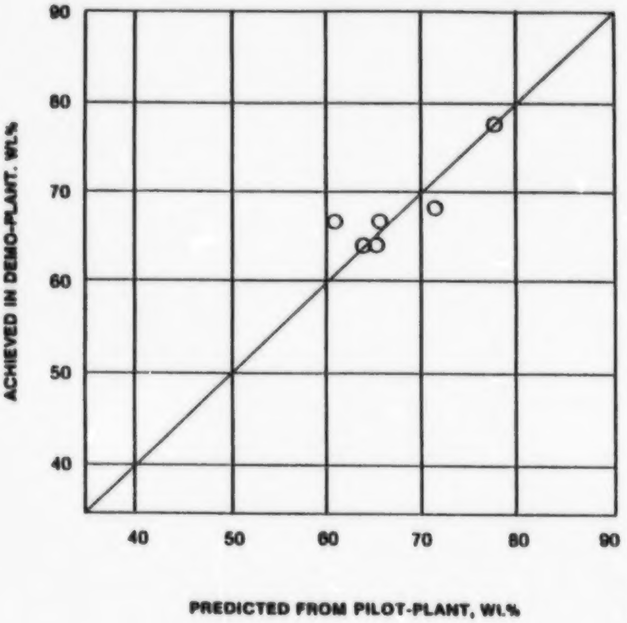
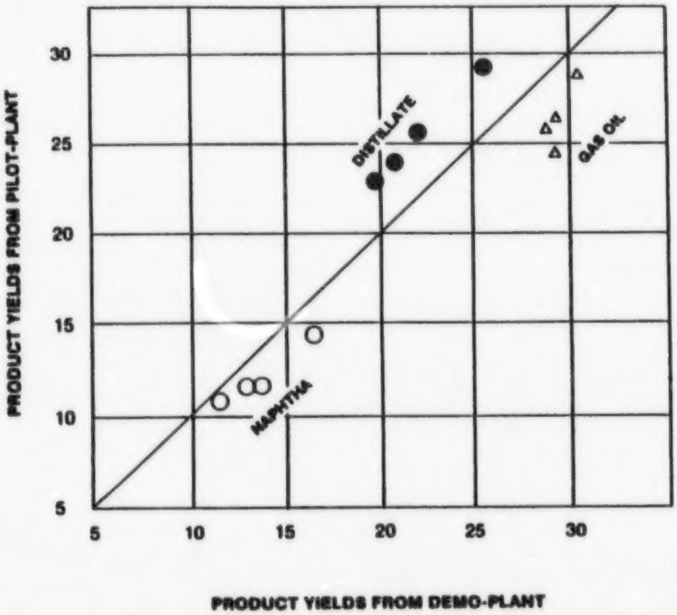


Figure 5



Pitch conversion achieved in the demo. plant compared to the pitch conversion predicted from pilot plant results.



Product yields from the demo. plant compared to product yields from the pilot plant.

50

HOW TO SELECT AN UPGRADING PROCESS TO SUIT YOUR NEEDS

A CASE STUDY

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ABSTRACT

LC-finer hydrocracking has been selected for the world's largest heavy oil upgrader - Syncrude - for its present capacity addition program and its future expansion project. The selection is based on the overall performance of the plant with its present facilities and on commercially available hydrocracking processes and their capability of providing higher liquid yield, reduced coke production, reduced sulfur emissions, improved product quality, and optimized economics.

INTRODUCTION

Bituminous sands (tar sands or oil sands) occur in various places in the world. The Athabasca deposit in Northern Alberta, being developed by Syncrude and other companies, is believed to be the second largest and has the advantages of being:

- *geographically accessible*
- *in a region where the necessary technical support is well established*
- *shallow enough in parts for open pit mining.*

The Syncrude leases are located in the area where the overburden is shallow thus the company has been able to employ a surface mining scheme. The overburden is first removed by shovels and trucks, and then the useable bituminous sand is mined with draglines and piled in windrows along the sides of the mine pit. This approach allows Syncrude to supply ore to the extraction plant at a steady rate even in winter when the sands become frozen. In addition it makes it easier to handle ompacted clay and siltstone lenses that are interlayered with the bituminous sands.

The ore stored in windrows is quite loose and is transferred to conveyor belts by bucket wheel reclaimers. The conveyors transport the ore to the extraction plant.

The sand particles are surrounded by a thin film of water and this separates the sand and bitumen from each other. This is the key property on which the hot water separation process used by Syncrude depends. Due to this thin layer of water, the sands merely have to be agitated in a body of warm water to reduce the "viscosity" (resistance to flow) of the bitumen to a point where it will float free of the solids. In practice this is done in a tumbler. The ore is introduced along with hot water, steam to adjust the temperature, and chemicals that aid the process. The tumbler product is a slurry with the bitumen and sand in loose association. The slurry is diluted with more hot water and screened to remove pebbles and lumps of undigested bituminous sands.

The screened slurry is then fed into a Primary Separation Vessel. Here the bitumen globules float as a froth (Primary froth) with about 65% bitumen. The sand settles out and is then pumped to the Tailings Oil Recovery (TOR) vessels. These vessels are designed to recover approximately 50% of the bitumen previously lost to the tailings pond. A further yield of froth is recovered by the secondary flotation plant which processes middlings from the TOR vessels. Froth from the TOR and secondary flotation plant is combined with primary froth from the Primary Separation Vessels and is fed to the centrifuge plant.

To remove solids and water, the bitumen component of the combined froth is diluted with naphtha to render it less dense and less viscous, and the mixture is centrifuged. The naphtha is removed from the centrifuge product by distillation (for reuse) leaving pure bitumen. The tailings from the centrifuge plant are passed through the Naphtha Recovery Unit where 70% of the naphtha not removed by the centrifuge is recovered by a vacuum distillation process.

The materials which remain after the bitumen has been extracted from the oil sands are called "tailings" and are accommodated in the 18-square kms. (approximately) tailings pond area. Tailings from the Extraction plant consist mostly of sand while those from the Froth Treatment plant are mostly small clay particles and some hydrocarbons. As the tailings settle out, the clarified water is recycled for reuse in processing.

During the summer and fall the tailings pond surface is skimmed to remove bitumen that escapes from the extraction process.

The bitumen is a heavy oil; it has a high molecular weight, a high boiling point and viscosity (Table 1). To be useful, it must be converted to lighter material.

Bitumen is sprayed into a heated chamber called a coker. Under these conditions it "cracks" (the molecules break down to smaller units). At the same time, some carbon is rejected and forms coke granules that are able to flow out of the unit (hence the name given to the process -- fluid coking). Heat is provided for the cracking step by partly burning some of the coke in another chamber and returning the hot coke to the cracking chamber.

The feed to the secondary upgrading step is high in sulfur, nitrogen, metals and unsaturates. It is split into raw naphtha and raw gas oil and two streams react with hydrogen at high pressure and temperature in the presence of a catalyst. The sulfur is removed in the form of hydrogen sulfide which is later converted to elemental sulfur. Nitrogen is removed as ammonia which is flared. The upgraded products are combined and the resulting mixture is high grade synthetic crude oil. Its property is illustrated in Table 2.

EXPANSION OF SYNCRUDE

The initial Syncrude project, completed in 1978, had a design capacity of 39.5 MBBL/year (or 6.27 MM^3/year). In 1988, Syncrude will complete a 6-year capital investment program (known as the Capital Addition Program or CAP) to increase its output to 59.3 MBBL/year (or 9.4 MM^3/year) of saleable hydrocarbon.

Now Syncrude is undertaking a completion of the development and basic engineering for Expansion. After Expansion, the new plant facilities are anticipated to be capable of producing some 94.4 MBBL/year (or 15 MM^3/year) saleable hydrocarbon. The development of the CAP and the Expansion project for Syncrude provided an opportunity to review the requirements of these processes and make changes. The selection of only the Primary Upgrading Process, a small portion of the total work, will be discussed here.

OBJECTIVES

A primary upgrading process to be selected for the Capacity Addition Program (CAP) and Expansion had to meet the objectives of:

- *Reduced Production Dependence Upon any Single Unit:*

  Most of the present upgrading facility (Figure 1) will be integrated into the modified or new primary upgrading process used in CAP (Figure 2) and in Expansion (Figure 3). This will provide the future Syncrude plant with the ability to produce continuously all year around. In the past, turn-arounds of the fluid cokers forced the plant to a total stall.

- *Retained Fluid Cokers:*

  The fluid cokers of the present plant have performed at a high level of service and also represent a major investment of Syncrude. There will be no significant modification proposed to the units, although feedrate will be somewhat reduced.

- *Increased Yield of Synthetic from Bitumen:*

  The present upgrading processes perform at an overall synthetic crude oil yield on bitumen of 81%. After the completion of CAP a yield of 84% is to be achieved, with an incremental yield of 106% obtained with Expansion, to provide an overall yield of 92%.

- *Reduced Coke Production per Barrel of Syncrude Crude Oil:*

  One of the products from the fluid coking process is coke. The coke contains a relatively high amount of sulfur, ash and metals. Approximately 2000 tonnes/CD coke is being produced and stock piled in a coke pond for future use. In general, coke production is proportional to the Conradson Carbon residue (CCR) of the feedstock to the fluid coker. A primary upgrading process able to achieve high CCR conversion would help to reduce the formation of coke in the intergrated upgrading plant.

☐ *Reduced Sulfur Emission:*

Sulfur emission from an expanded Syncrude plant will be influenced by unit feedrates, bitumen sulfur content, sulfur content of hydrocracker residue fed to the cokers, sulfur in the produced coke in the coke burner, quantity of coke burned, and sulfur recovery efficiency. Detailed design of the sulfur recovery system is not within the scope of this paper, however, a well selected hydrocracker with subsequent sulfur recovery units should be able to accomplish the goal of reducing the absolute sulfur emissions. Syncrude has committed to reduce sulfur emissions with an increased production rate, as illustrated in Figure 4. The incremental sulfur emission from expansion units is to reach zero discharge.

☐ *Maintained or Improved Product Quality:*

It has been established that synthetic crude oil will receive an incremental price increase for all product over 31° API. The selected hydrocracking unit is expected to increase overall product quality by 1° API

☐ *Optimized Economics:*

The primary upgrading process cannot stand alone in the economic evaluation. The overall investment required to integrate the present facility with additional hydrocracking and associated processing facilities must aid in the overall financial viability of the project.

CRITERIA FOR SELECTION

Five criteria used by Syncrude to select a primary upgrader in the Capacity Addition Program are:

☐ *suitability for Syncrude's bitumen*

☐ *commercially proven*

☐ *achieve high CCR conversion*

☐ *ability to reduce sulfur and nitrogen content*

☐ *achieve high pitch conversion.*

In total, fourteen primary upgrading alternatives were considered prior to the selection of the hydrocracker in CAP. However, nine of the alternatives were rejected on initial review because they were either commercially unproven or achieved low CCR conversion of coke producing material (see Table 3).

The alternative of further debottlenecking of existing cokers did not meet Syncrude's objectives.

The final four primary upgrading processes given further consideration were:

☐ *feed fractionation (with 650° F and 800° deg. F cut point*

☐ *the construction of a third fluid coker*

☐ *installation of a flexicoker*

☐ *an ebullated bed bitumen hydrocracker.*

Schematic flow diagrams of these options are provided in Figures, 6, 7, 8, and 9. A comparison of these alternatives is smmarized as Table 4.

CONCLUSION

The LC-fining process is clearly the most attractive process. It achieves a high yield of sufficient liquid prducts. The high operations costs are offset by the decreased hydrotreater costs associated with higher sulfur and nitrogen conversion levels in the LC-finer. In particular, the fact that the process is commerically proven makes it the most attractive of the processes evaluated.

Although the Aurabon process was deemed commercially sound, discussions with the licensor concluded that the data was insufficient for Syncrude to reach any meaningful conclusions within the time frame of the evaluation. In addition, the Auabon process is used mainly for demetallization and is not suited for CCR reduction, pitch conversion, and hydrodesulfurization. For these reasons the process did not meet Syncrude's evaluation criteria.

The Shell Moving Bed process is similar to the fixed-bed hydrotreater which has not been demonstrated for heavy feeds containing solids. Solids in the bitumen feed could therefore result in bed plugging which would reduce the plant service factor. Syncrude felt that the Shell Moving Bed process is unsuitable for bitumen.

Identical results have also been obtained in the evaluation of primary upgrading processes for the Expansion.

ACKNOWLEDGEMENT

The authors wish to thank Syncrude Canada Ltd. for granting the permission to present the paper and Messers P. Bates, V. Nowlan, and P. Mankowski for their assistance in the preparation of this paper.

Table 1
Athabasca Feed Qualities

Analytical Results	
Gravity, °API	7.4
Carbon, wt.%	83.13
Hydrogen, wt.%	9.82
Sulfur, wt.%	4.54
Nitrogen, wt.%	0.426
Oxygen, wt.%	1.12
Conradson Carbon, wt.% [1]	12.7/14.0
Micro Carbon, wt.%	14.1/14.0
Ash, wt.%	0.90
Metals, ppm	
Ni	68
V	234
Fe	408
Ni-Vac C Distillation, °F	
2 LV%	565
5	612
10	673
20	754
30	853
40	963
50	1039
60	
FBP	1050
LV% off at FBP	53

[1] Conradson and Micro Carbon residue results are ash-inclusive.

Table 2
Synthetic Crude Assay - Analytic Data

Test	Synthetic Crude Charge	Cut I 28-110 °C	Cut II 110-170 °C	Cut III 170-198 °C	Cut IV 198-248 °C	Cut V 248-290 °C	Cut VI 290-331 °C	Cut VII 331-380 °C	Cut VIII 380 + °C
Yield LV%		7.8	7.0	4.7	12.8	13.0	14.0	15.0	21.7
Specific Gravity, 20/20	.8631	.6911	.7745	.8148	.8519	.8788	.9032	.9262	.9490
Total Sulfur, W PPM	1120	3.2	1.3	2.2	10.8	64.9	584	2140	2590
Total Nitrogen, W PPM	586	0.1	1.4	6.0	14.8	45.4	180	761	1700
Basic Nitrogen, W PPM	73				12	30	80	96	177
Cloud Point, °C				-68	-64	-50	-28	-10	
Pour Point, °C				-80	-68	-60	-39	-33	
Freezing Point, °C				-68.5	-68.5	-45.1			
Kinematic Viscosity cst. @ °C	3.223			1.014	1.504	3.062	6.086	11.34	168.1
Kinstatic Viscosity cst. @ °C	1.378					1.129	1.920	3.472	10.63
Paraffins, LV%		58.9	40.9	33.7	18.4	13.0	5.7	4.1	3.6
Naphthenes, LV%		26.7	42.6	41.2	45.1	42.3	38.9	34.7	34.5
Aromatics, LV%		4.4	16.6	25.2	36.5	44.7	56.4	61.2	61.9
Cetane Index									
Aniline Point, °C				38.6	39.1	42.4	47.8	50.2	67.9
Refractive Index @ 67°C								1.4967	
R.C.R., wt.%						0.10	0.12	0.13	0.49

Table 3
Primary Upgrading Alternatives Rejected On Initial Review

		Criteria				
Process	Comments	Suitable for Bitumen [1]	Proven Commercial [1]	CCR [2] Conversion	Resid. HDS	Pitch Conversion
Shell Moving Bed	- Primarily a demetalization process. - Fixed-bed Hydrotreating using a single moving bed.	No	Yes	Low	Yes	Low
CANMET	- Fine coal-iron additive slurried with feed. - Slurry reacted with H^2 at high pressure.	Yes	No	Low	Low	60% to 95%
Veba Oel	- Catalyst slurried with feed (optional). - 2 stages of reactors. - Liquid phase hydrogenation followed by vapour stage (fixed bed). - Very high pressure.	Yes	No	Low	Low	High
M-Coke	- Hydrocracking promoted by molybdenum deposited fine coke particles. - High pressure.	Yes	No	Medium	Low	60% to 95%
Aurabon	- Catalytic demetalization asphaltene reduction. - Used for feed pretreatment.	No	Yes	Low	Low	Low
Donor Refined Bitumen	- Hydrocracking by donor solvent. - Low pressure.	Yes	No	Low	Low	Low-Medium
Art	- Basically a once through fluid coker. - Burner large enough to consume all the coke produced. - Produces a highly unstable resid product.	Yes	Yes	No	No	Yes
Eureka	- Thermal cracking process. - Produces a net resid withdrawn via a flacker as a solid by-product. - Oil yield no better than coking.	Yes	Yes	No	No	Yes
Delayed Coking	- Batch coking process. - Lower liquid yields and higher coke make than fluid coking.	Yes	Yes	No	No	Yes

[1] Syncrude's opinion

[2] Conradson Carbon residue

Table 4
Summary Of The Comparison Of Primary Upgrading Process Alternatives Given Further Consideration

Process Alternative	Incremental SCO Production (MBBL/YR) [1]	Incremental SO_2 Emissions (wt.%)	Relative Capital Cost	Hydrogen Demand (SCF/BBL Bitumen)	Other Advantages	Other Disadvantages
Feed Fractionation						
650°F +	4.1	0	Low	874	- Technically simple.	- Could reduce service factor.
800°F +	4.1	-10	Medium	846	- Technically simple.	- Lower SCO gravity. - Increased net coke make. - Could reduce service factor.
Fluid Coker	4.7	+10	Medium	888	- Same as existing. - Run 3 cokers at reduced rates. Therefore, could improve service factor.	- No increase in SCO gravity. - Additional coke production.
Flexi-Coker	4.7	-7	High	888	- Reduced net coke. - Run 3 cokers at reduce rates. Therefore, could improve service factor.	- No increase in SCO gravity. - New to SCL.
Hydrocracker	6.4	-5	Medium	1015	- Reduced net coke. - Increases SCO gravity and quality.	- New to SCL.

[1] Assuming same service factor for all cases (0.81) and the same bitumen charge to primary upgrading

Figure 1
Schematic Flow Sheet for Principal Hydrocarbon Streams of Existing Syncrude Facilities

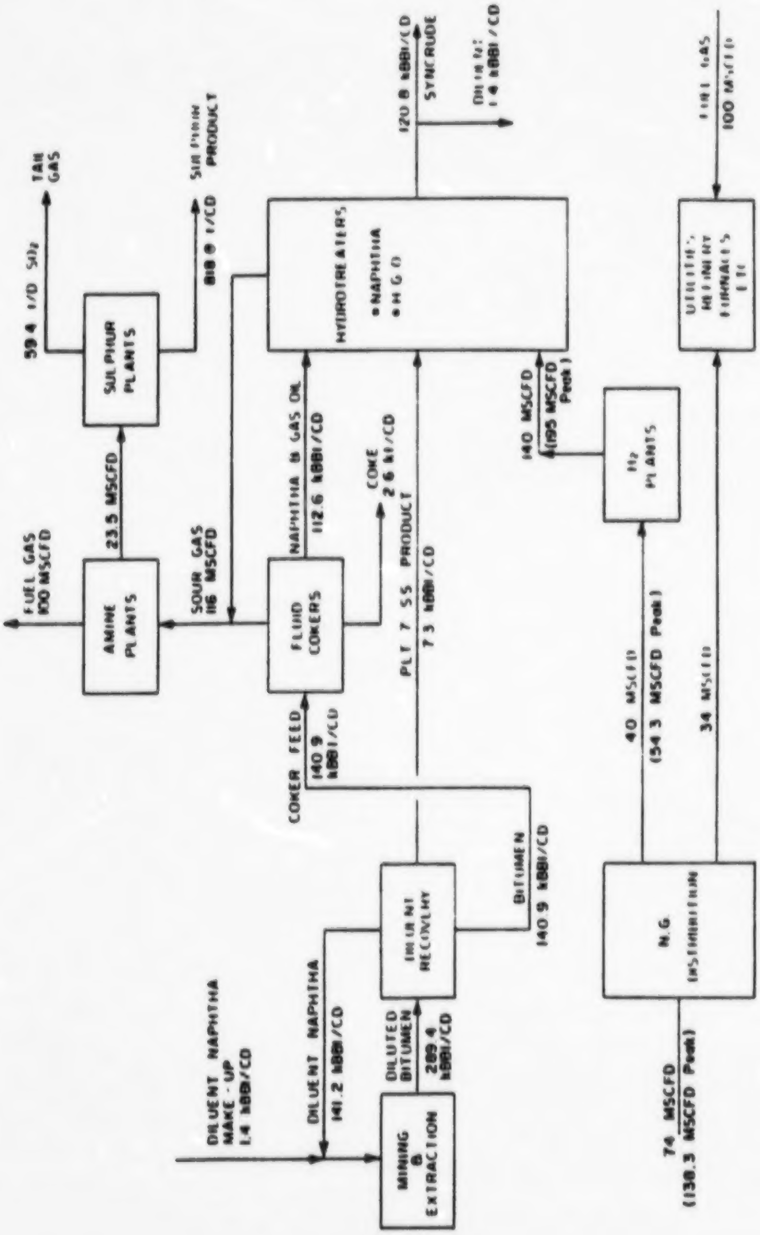

DILUENT NAPHTHA MAKE - UP 1.4 kBBl/CD
DILUENT NAPHTHA 141.2 kBBl/CD
MINING & EXTRACTION
DILUTED BITUMEN 289.4 kBBl/CD
DILUENT RECOVERY
BITUMEN 140.9 kBBl/CD
COKER FEED 140.9 kBBl/CD
FLUID COKERS
COKE 2.6 kt/CD
PLT 7 SS PRODUCT 7.3 kBBl/CD
SOUR GAS 116 MSCFD
AMINE PLANTS
FUEL GAS 100 MSCFD
23.5 MSCFD
SULPHUR PLANTS
59.4 t/D SO_2
TAIL GAS
818.9 t/CD
SULPHUR PRODUCT
NAPHTHA & GAS OIL 112.6 kBBl/CD
HYDROTREATERS
• NAPHTHA
• H G O
120.8 kBBl/CD SYNCRUDE
DILUENT 1.4 kBBl/CD
140 MSCFD (195 MSCFD Peak)
H_2 PLANTS
40 MSCFD (54.3 MSCFD Peak)
N.G. DISTRIBUTION
74 MSCFD (138.3 MSCFD Peak)
34 MSCFD
UTILITIES REFINERY FURNACES ETC
FUEL GAS 100 MSCFD

Figure 2
Schematic Flow Sheet for Principal Hydrocarbon Streams of Syncrude Facilities Following Completion of New Facilities

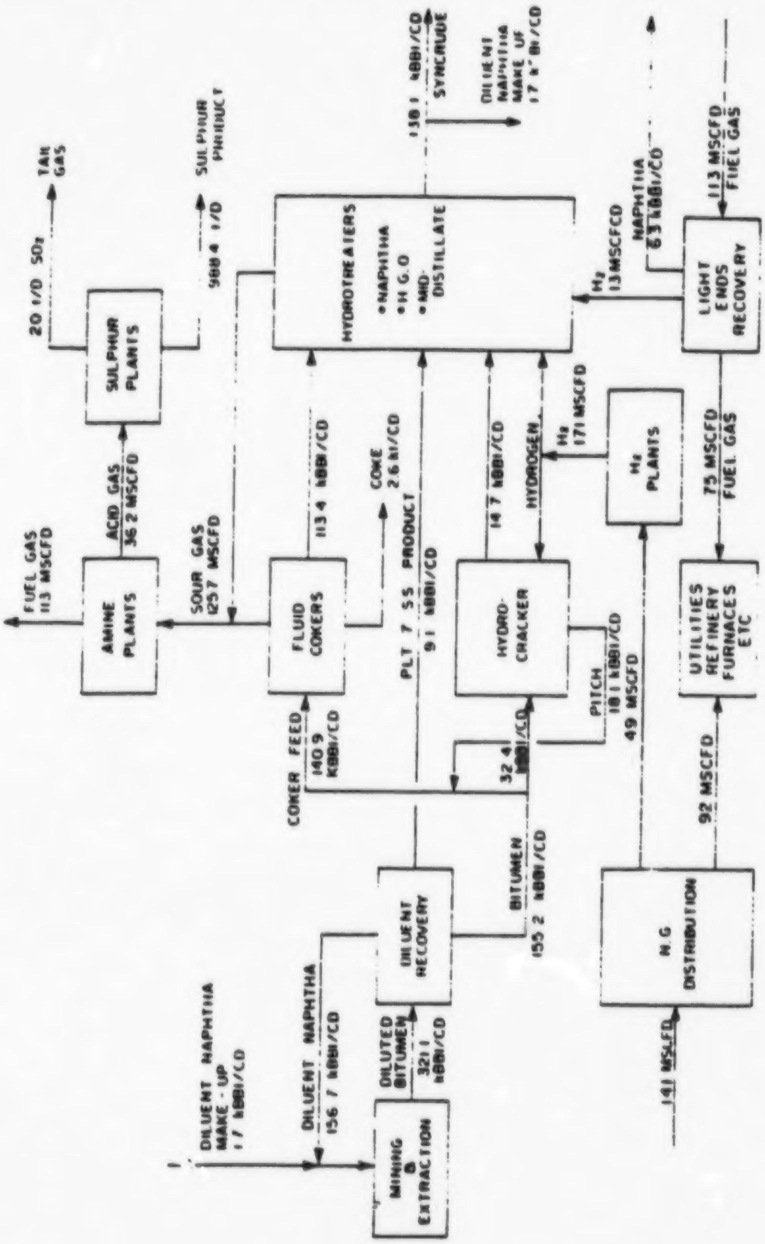

MINING & EXTRACTION
DILUENT NAPHTHA MAKE - UP 1.7 KBBl/CD
DILUENT NAPHTHA 156.7 KBBl/CD
DILUTED BITUMEN 321.1 KBBl/CD
DILUENT RECOVERY
BITUMEN 155.2 KBBl/CD
COKER FEED 140.9 KBBl/CD
32.4 KBBl/CD
FLUID COKERS
SOUR GAS 1257 MSCFD
AMINE PLANTS
FUEL GAS 113 MSCFD
ACID GAS 36.2 MSCFD
SULPHUR PLANTS
20 T/D SO2
TAIL GAS
988.4 T/D
SULPHUR PRODUCT
COKE 2.6 kT/CD
113.4 KBBl/CD
PLT 7.55 PRODUCT 9.1 KBBl/CD
HYDRO-CRACKER
PITCH 18.1 KBBl/CD 49 MSCFD
14.7 KBBl/CD
HYDROGEN
H2 171 MSCFD
H2 PLANTS
HYDROTREATERS
• NAPHTHA
• H.G.O
• MID-DISTILLATE
138.1 KBBl/CD SYNCRUDE
DILUENT NAPHTHA MAKE UP 1.7 KBBl/CD
H2 13 MSCFD
NAPHTHA 6.3 KBBl/CD
113 MSCFD FUEL GAS
LIGHT ENDS RECOVERY
75 MSCFD FUEL GAS
UTILITIES REFINERY FURNACES ETC
92 MSCFD
N.G DISTRIBUTION
141 MSCFD

Figure 3
Schematic Flow Sheet for Principal Hydrocarbon Streams of Syncrude Facilities Following Expansion

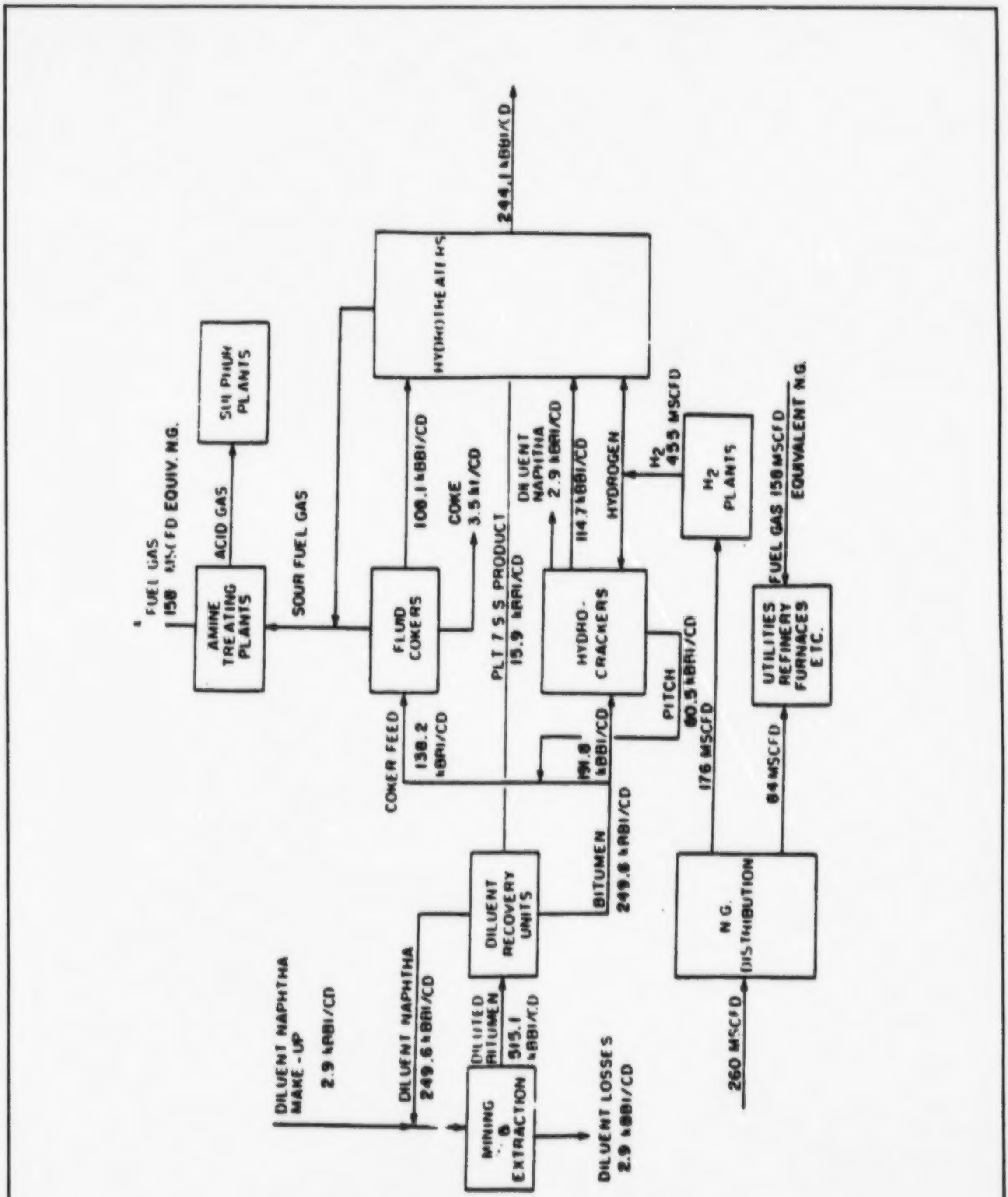

FUEL GAS 158 MSCFD EQUIV. N.G.
AMINE TREATING PLANTS
ACID GAS
SULPHUR PLANTS
SOUR FUEL GAS
FLUID COKERS
108.1 kBBl/CD
COKE 3.5 kT/CD
HYDROTREATERS
244.1 kBBl/CD
PLT 7 S.S PRODUCT 15.9 kBBl/CD
DILUENT NAPHTHA 2.9 kBBl/CD
114.7 kBBl/CD
HYDROGEN
H2 455 MSCFD
H2 PLANTS
FUEL GAS 158 MSCFD EQUIVALENT N.G.
HYDRO-CRACKERS
PITCH 60.5 kBBl/CD
UTILITIES REFINERY FURNACES ETC.
COKER FEED 138.2 kBBl/CD
191.8 kBBl/CD
176 MSCFD
84 MSCFD
BITUMEN 249.8 kBBl/CD
DILUENT RECOVERY UNITS
N.G. DISTRIBUTION
DILUENT NAPHTHA MAKE-UP 2.9 kBBl/CD
DILUENT NAPHTHA 249.6 kBBl/CD
DILUTED BITUMEN 515.1 kBBl/CD
260 MSCFD
MINING & EXTRACTION
DILUENT LOSSES 2.9 kBBl/CD

Figure 4
Historical Comparison of the Sulphur Dioxide Emissions per Thousnad Barrels of Synthetic Crude Production from Syncrude

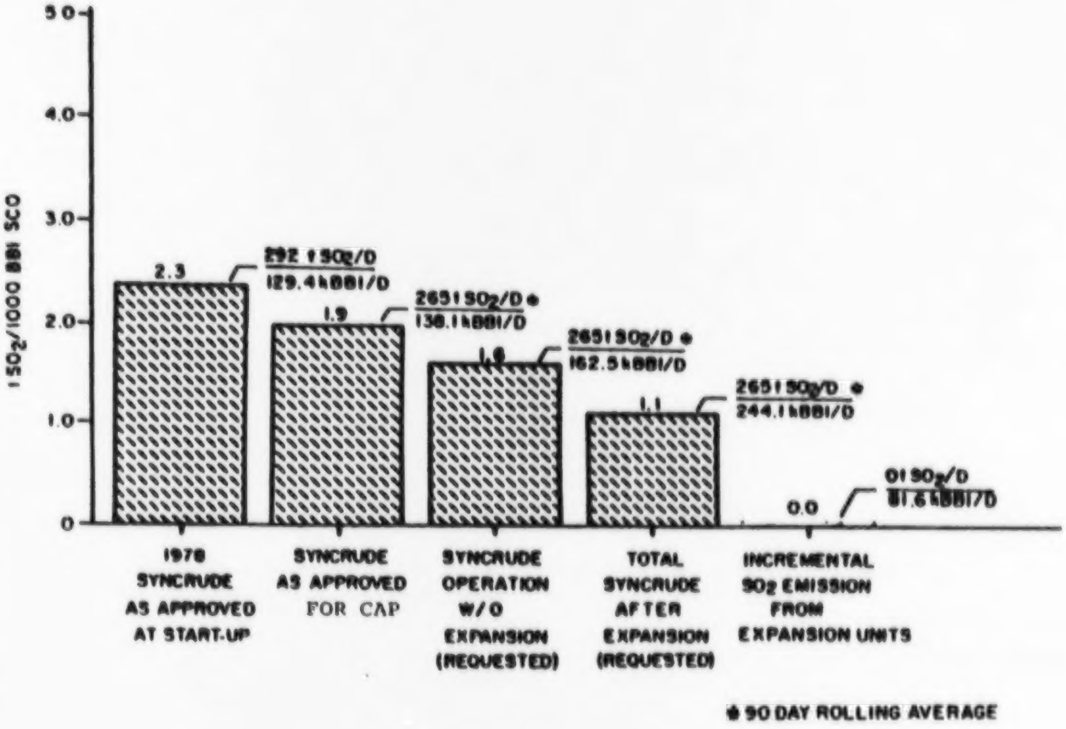


Figure 5
Schematic Flow Sheet for the New Ebullating Bed Bitumen Hydrocraker Case Selected by Syncrude

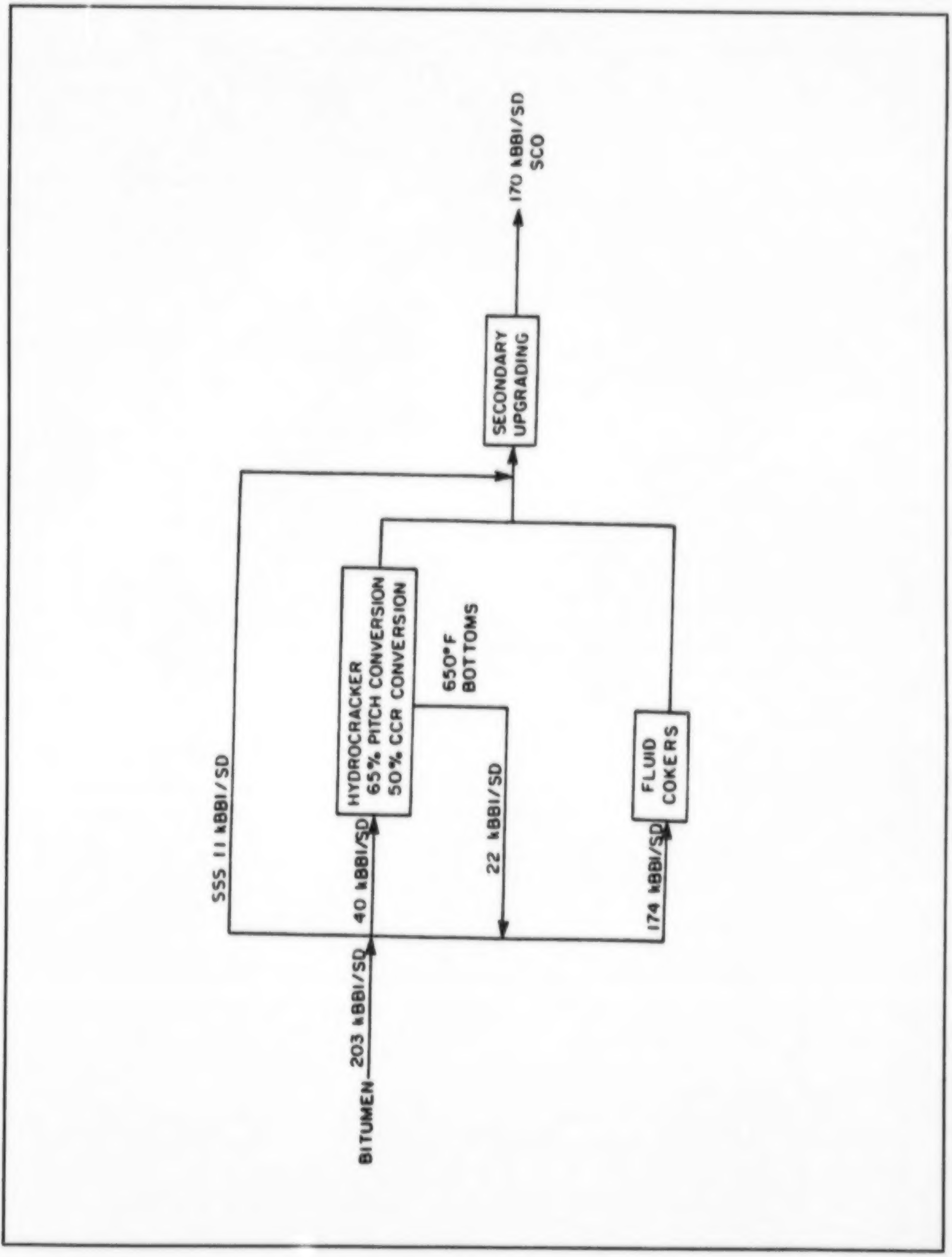

BITUMEN
203 kBBl/SD
SSS 11 kBBl/SD
40 kBBl/SD
HYDROCRACKER
65% PITCH CONVERSION
50% CCR CONVERSION
650°F
BOTTOMS
22 kBBl/SD
174 kBBl/SD
FLUID
COKERS
SECONDARY
UPGRADING
170 kBBl/SD
SCO

Figure 6
Schematic Flow Sheet for the Ebullated Bed Bitumen Hydrocraker Case Considered

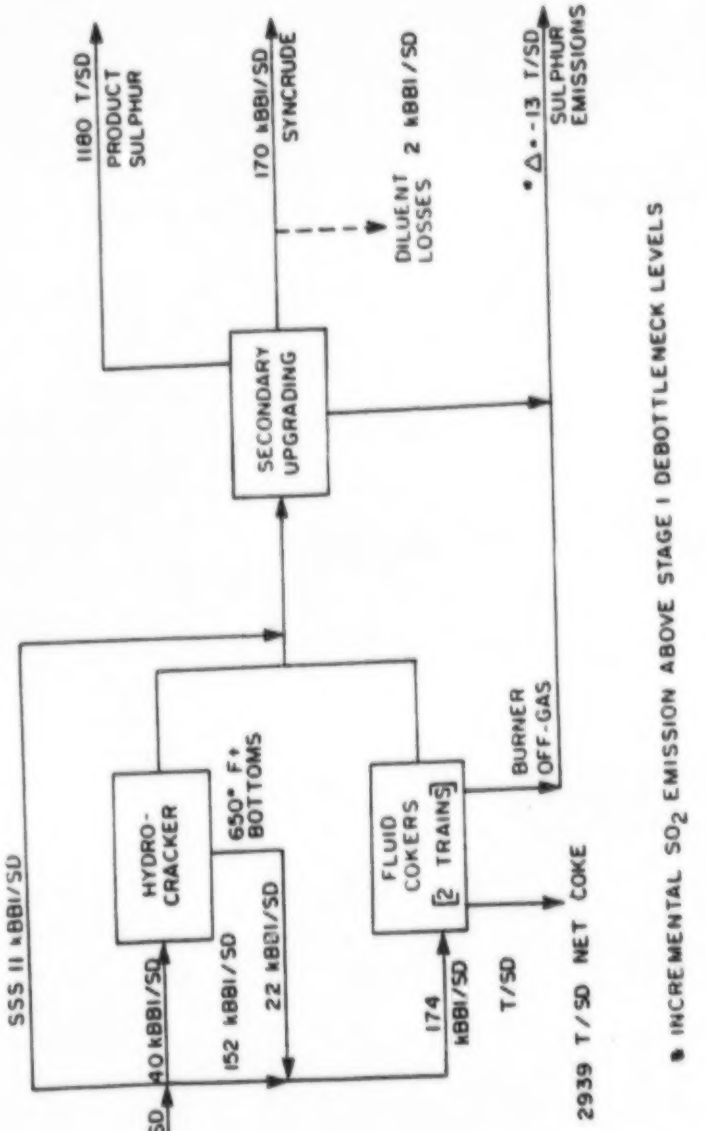

203 kBBl/SD
BITUMEN
SSS 11 kBBl/SD
40 kBBl/SD
152 kBBl/SD
22 kBBl/SD
HYDRO-
CRACKER
650° F+
BOTTOMS
174
kBBl/SD
FLUID
COKERS
[2 TRAINS]
T/SD
2939 T/SD NET COKE
BURNER
OFF-GAS
SECONDARY
UPGRADING
1180 T/SD
PRODUCT
SULPHUR
170 kBBl/SD
SYNCRUDE
DILUENT
LOSSES 2 kBBl/SD
* Δ = -13 T/SD
SULPHUR
EMISSIONS
* INCREMENTAL SO_2 EMISSION ABOVE STAGE I DEBOTTLENECK LEVELS

Figure 7
Schematic Flow Sheet for the Additional Fluid Coker Case Considered

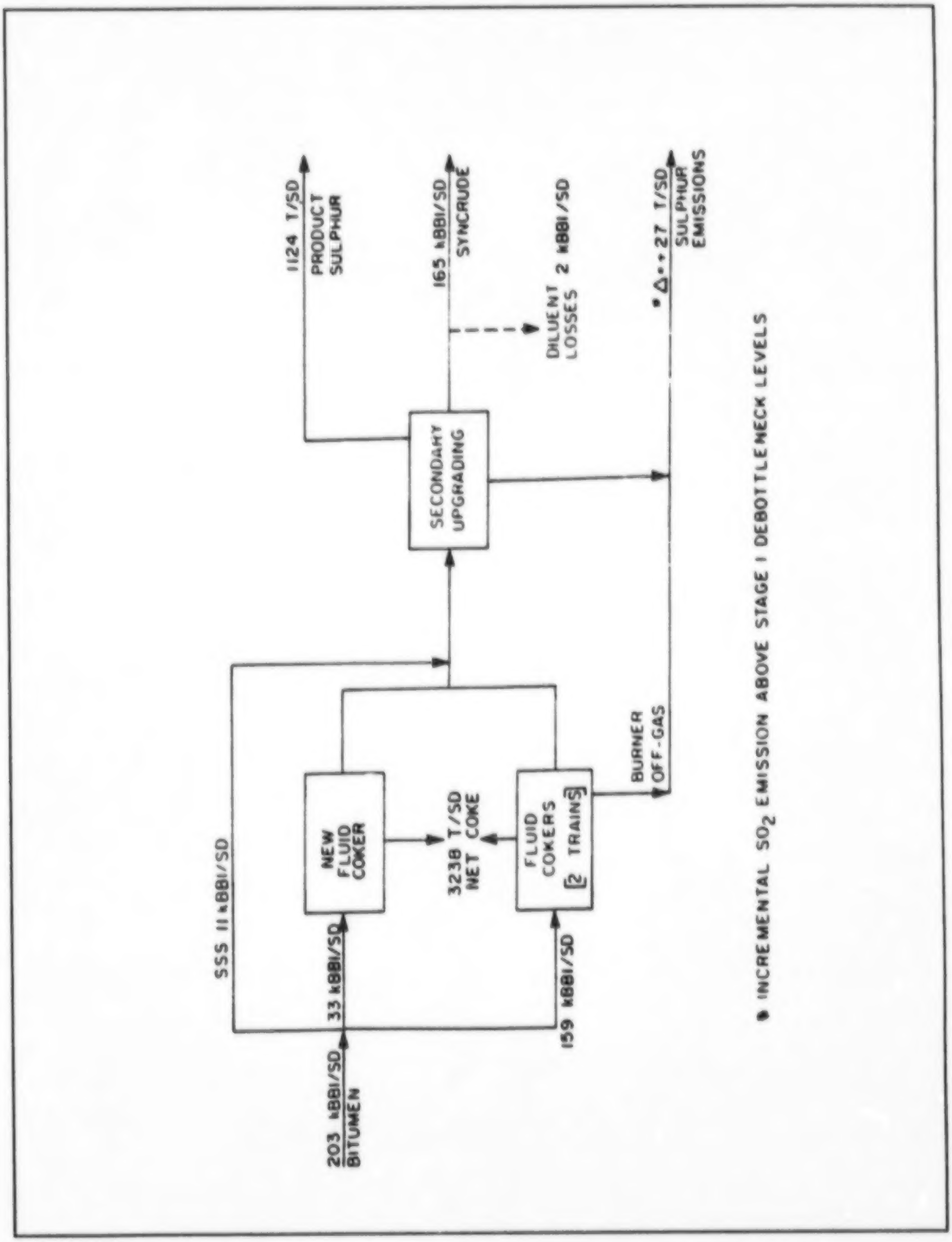

203 kBBl/SD
BITUMEN
SSS 11 kBBl/SD
33 kBBl/SD
159 kBBl/SD
NEW FLUID COKER
FLUID COKERS [2 TRAINS]
3238 T/SD
NET COKE
BURNER OFF-GAS
SECONDARY UPGRADING
1124 T/SD
PRODUCT SULPHUR
165 kBBl/SD
SYNCRUDE
DILUENT LOSSES 2 kBBl/SD
*Δ = +27 T/SD
SULPHUR EMISSIONS
* INCREMENTAL SO_2 EMISSION ABOVE STAGE I DEBOTTLENECK LEVELS

Figure 8
Schematic Flow Sheet for the Feed Fractionation (800°F Cutpoint) Case Considered

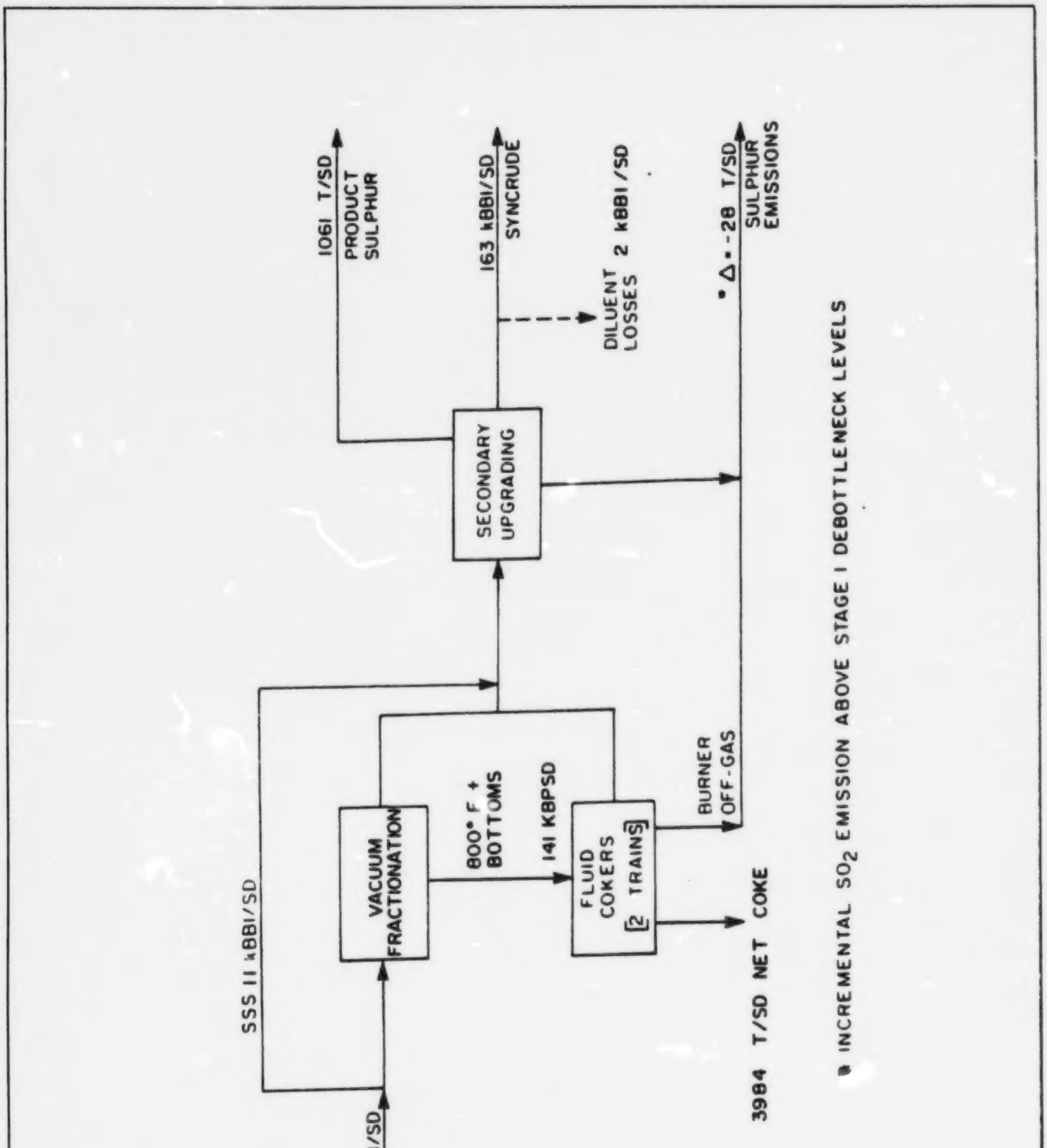
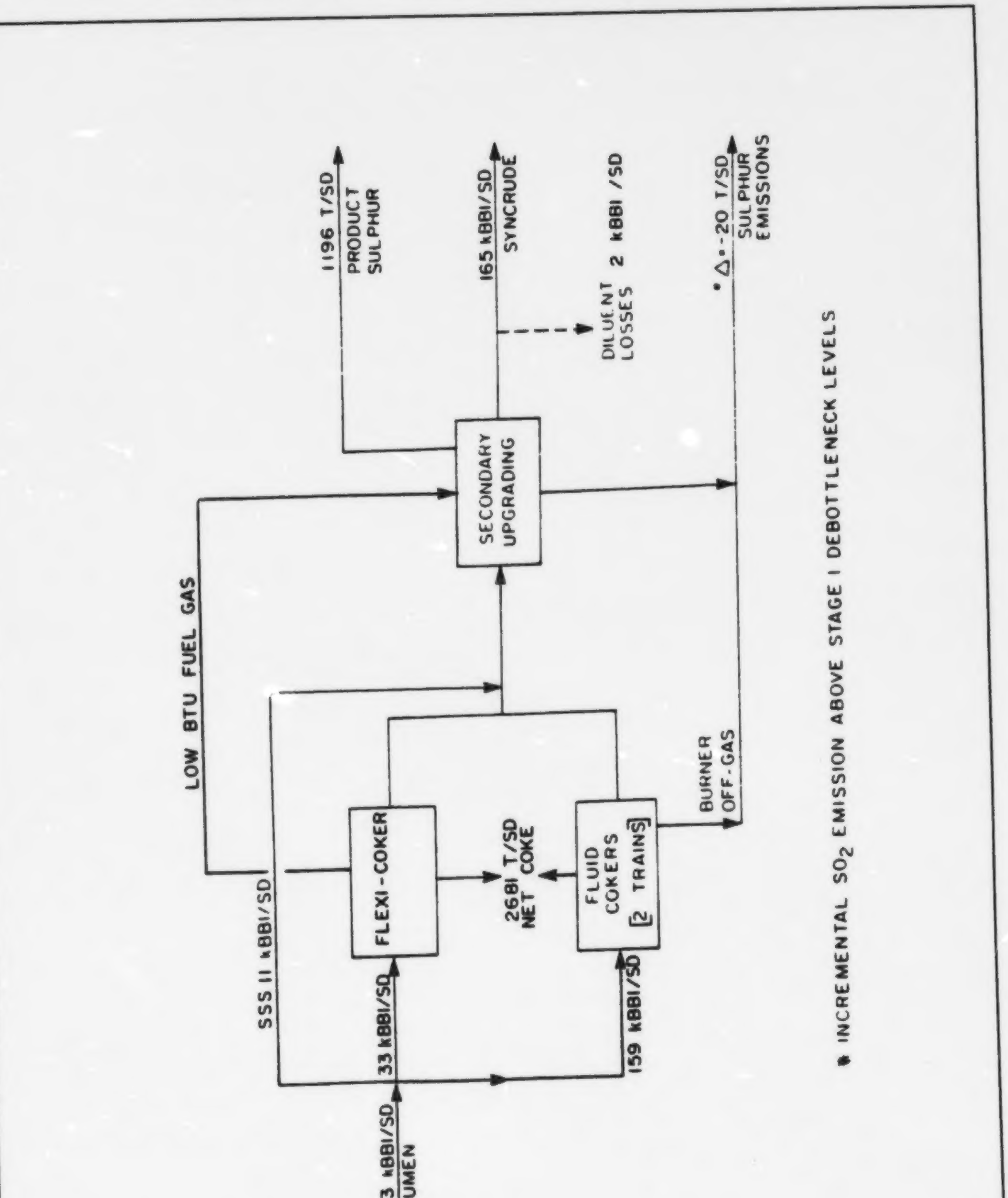

203 kBBl/SD
BITUMEN
SSS 11 kBBl/SD
VACUUM FRACTIONATION
800° F + BOTTOMS
141 KBPSD
FLUID COKERS [2 TRAINS]
3984 T/SD NET COKE
BURNER OFF-GAS
SECONDARY UPGRADING
1061 T/SD
PRODUCT SULPHUR
163 kBBl/SD
SYNCRUDE
DILUENT LOSSES 2 kBBl/SD
* Δ = -28 T/SD
SULPHUR EMISSIONS
* INCREMENTAL SO$_2$ EMISSION ABOVE STAGE I DEBOTTLENECK LEVELS

Figure 9
Schematic Flow Sheet for the Flexi-Coker Case Considered


203 kBBl/SD
BITUMEN
33 kBBl/SD
159 kBBl/SD
SSS 11 kBBl/SD
FLEXI-COKER
FLUID COKERS [2 TRAINS]
2681 T/SD NET COKE
LOW BTU FUEL GAS
BURNER OFF-GAS
SECONDARY UPGRADING
1196 T/SD PRODUCT SULPHUR
165 kBBl/SD SYNCRUDE
DILUENT LOSSES 2 kBBl /SD
* Δ = -20 T/SD SULPHUR EMISSIONS
* INCREMENTAL SO2 EMISSION ABOVE STAGE I DEBOTTLENECK LEVELS